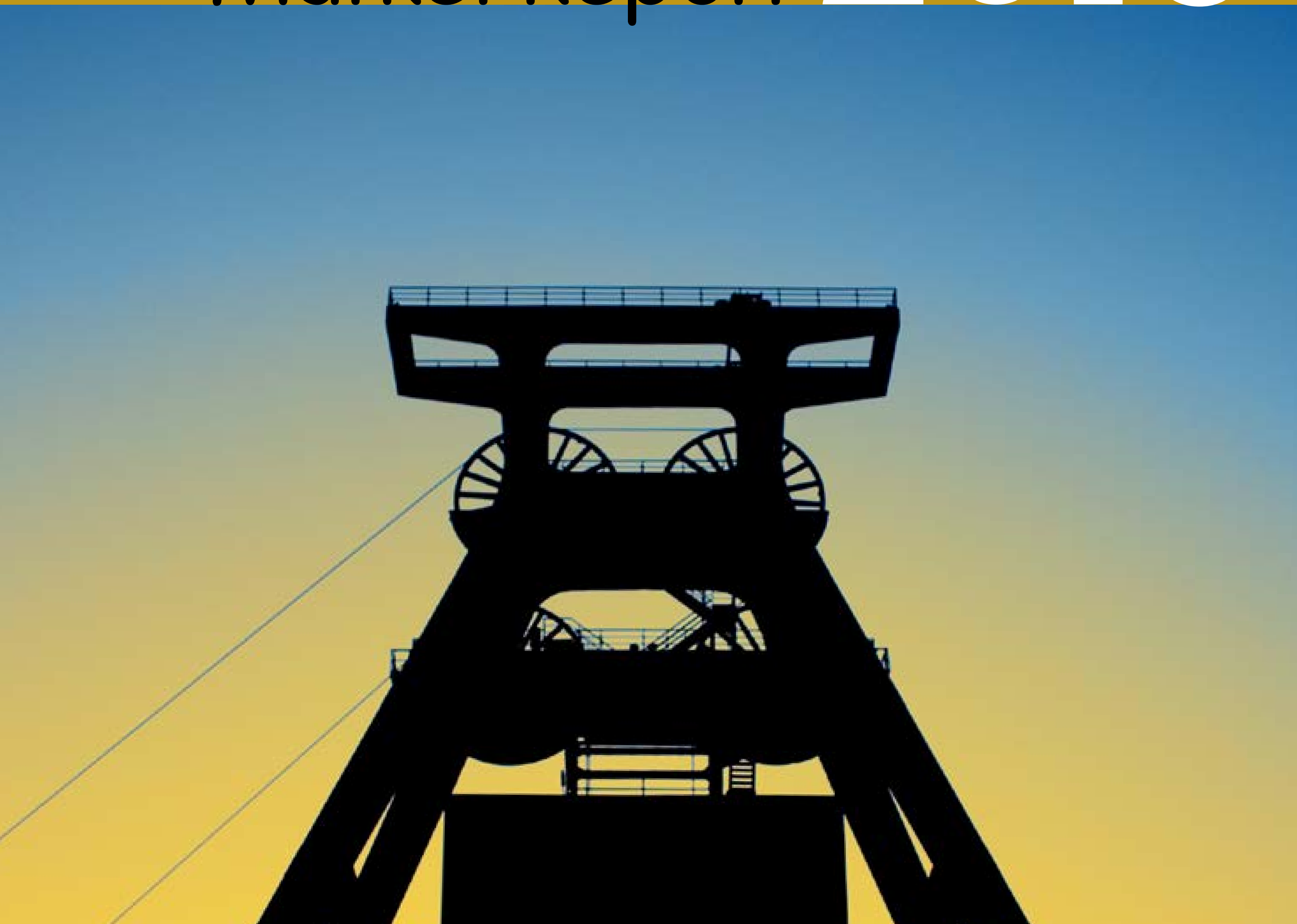
COAL

Medium-Term Market Report 2016



Market Analysis and Forecasts to 2021

International Energy Agency

Secure
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INTERNATIONAL ENERGY AGENCY

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- Secure member countries' access to reliable and ample supplies of all forms of energy; in particular, through maintaining effective emergency response capabilities in case of oil supply disruptions.
- Promote sustainable energy policies that spur economic growth and environmental protection in a global context – particularly in terms of reducing greenhouse-gas emissions that contribute to climate change.
- Improve transparency of international markets through collection and analysis of energy data.
- Support global collaboration on energy technology to secure future energy supplies and mitigate their environmental impact, including through improved energy efficiency and development and deployment of low-carbon technologies.
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FOREWORD

Coal is the most controversial fuel for good reasons. On the one hand, it provides almost 30% of global primary energy and is the world's most popular fuel for generating electricity, producing steel and making cement. It is also relatively affordable and widely available. On the other hand, coal use is responsible for 45% of energy-related CO_2 emissions, as well as over 40% of SO_2, around 15% of NOx and emissions of fine particulate matter. As a result, analysis on coal too often tends to be one-sided, highlighting either the negative environmental consequences or the positive contributions to economic growth.

To truly understand the important role that coal plays -- for better or worse -- in the global energy system, it is critical that we examine both sides of the coin. This means understanding the implications of climate policies on the future for coal, while also coming to terms with what coal is doing – and will continue to do – for energy security, economic growth and energy access in developing and emerging economies.

In recent years, coal has been seen as a dying industry, both as a result of a greater awareness about climate change as well as growing competition from other energy sources like natural gas or renewables. In the last few years, global coal demand growth has stalled. While this has happened before, most recently in the 1990s, it is a notable change from the 4% annual growth seen over 2000 to 2013. Yet it is too early to say that coal is dead.

Sluggish economic growth and energy efficiency improvements are restraining power demand around the world. Combined with the deployment of wind and solar photovoltaic (PV), these global forces are squeezing conventional generation -- including coal. At the same time, carbon prices and other policies are making gas increasingly attractive, particularly in the United States. In this environment – defined by the United States and Western Europe – new coal power plants are rare and the existing aging fleet is steadily disappearing.

But there is another picture to consider, that of emerging economies with growing populations and prospects of robust economic growth. Some of them are dealing with frequent blackouts. Others are unable to provide electric power for everyone. For these countries – many in South and Southeast Asia – coal can provide affordable and secure electricity.

For instance, India, Indonesia, Pakistan and Bangladesh combined account for more than one quarter of the world's population, but only 7% of total global electricity use, with a large part of the population with no access to electricity at all. These four countries are endowed with significant coal reserves. New coal power generation capacity could lock-in large amount of CO_2 emissions for the next decades. Yet it could also help in bringing modern energy services to millions of people. This is the contradiction of coal. And this is why we need to find ways to make the use of coal more environmentally sustainable by ensuring that all countries that decide to use coal-fired power plants only build the latest ultra-supercritical technologies and plan for carbon capture and storage in the future.

China has shown what coal can do for economic development. Though the share of coal in the Chinese energy mix will certainly decrease, it will continue to be important to the Chinese economy for years to come. China's pivotal role in the coal market was proved again this year when international coal prices rallied following Chinese policy measures aimed at curbing oversupply. This led to a rise in coal imports and higher prices in China and elsewhere. As this shows, policies matter.

The IEA decided to launch the *Medium-Term Coal Market Report 2016* in Beijing this year. This choice reflects not only our determination to open the IEA's doors to major emerging economies, but more fundamentally, the importance of China and Chinese policies to global coal markets. Perhaps more than anyone, China understands both the value of the energy provided by coal, and the challenges it creates when used at great scale. It is my hope that this report will provide broader insights as we seek to ensure a sustainable energy mix that provides secure supplies, economic growth and global access.

Dr. Fatih Birol
Executive Director
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EXECUTIVE SUMMARY

Is the glass half full or half empty?

Global coal demand growth has stalled. Coal demand in 2016 will be below 2013 levels, confirming a new trajectory since the meagre growth in 2014 after more than a decade of 4% annual growth. In 2015, global coal consumption decreased for the first time in this century. The big decline in the People's Republic of China (hereafter "China") and the United States was not offset by growth in India, Indonesia, the Russian Federation and Viet Nam. In China, coal use declined in the major consuming sectors: electricity, steel and cement. Coal generation dropped, driven by a sluggish 0.5% electricity demand growth and the diversification policy, which led to hydro, nuclear, wind, solar and natural gas power generation growth. In the United States, coal power generation plummeted as a result of low natural gas prices and coal plant retirements pushed by Mercury and Air Toxics Standards (MATS); hence, coal consumption dropped by 15%, the largest annual decline ever, to levels not seen in more than 30 years.

The world is burning more coal than ever. Except for the 1920s and the 1990s, coal use in the world has been continuously increasing since the start of the Industrial Revolution. Now we are witnessing another halt, but, even so, if we consider coal consumption from a historical perspective, the world has never burned as much coal. Our forecast shows a slight increase after a few years of decrease, reaching 2014 levels only in 2021. Such a growth path would depend greatly on the Chinese trajectory. Given the growth in primary energy globally, this means that, according to our forecast, 2011 was the "peak" for coal's share in the energy mix in this century. Thus, whereas coal will continue to be the preferred source of power generation, the share will decline from over 41% in 2013 to around 36% in 2021.

A two-track coal world

Coal's shift to the East is accelerating. The decline of coal in Europe and North America continues as expected, and new policies (such as stronger climate policies) or technology developments (such as the declining cost of renewable-based electricity) may even accelerate such decline. In Europe, the tone of discussion over energy, in particular in the area of electricity, is subtly shifting from low carbon to low carbon and no coal. In the United States, amid all the discussion of the impact of the new political leadership on the coal sector, our forecast is almost 100 million tonnes (Mt) of coal demand decrease through 2021 to be added to 300 Mt from 2007 to 2015. At the same time, we forecast solid consumption to continue in North Asia (Japan, Korea and Chinese Taipei) and strong growth in South and Southeast Asia (India, Viet Nam, Indonesia, etc.), where coal-based electricity is one of the preferred options to increase power generation in growing economies with electricity shortage. China, despite consumption having likely peaked, will continue to be the largest coal consumer by far over the period.

A geographical divide on coal is emerging. Traditionally, coal has been considered less burdened by geopolitical issues around its production and trade, underpinned by easy logistics and reserves widely distributed across the world. However, the move of coal to Asia is accelerating and will continue in the coming years with the bulk of coal plant retirements occurring in Europe and the United States, and construction of new coal power plants happening mostly in Asia. If coal production, demand, trade and all coal-related technology and finance disappear from Europe and America while they are increasingly concentrated in Asia, a geographical split will emerge. The growing asymmetry related to coal could make coal more controversial and complicate discussions and negotiations on CO_2 emission mitigation.

A relieved industry

The unexpected boost to coal prices has provided the industry with relief. After a sustained decline over more than four years, coal prices have seen a strong rebound in 2016. Supply discipline, high cost mine closures and capital expenditures (capex) reduction have retired some output from the market. However, rather than a big change in the international supply/demand balance, the main driver of the rise has been the policy changes in China to cut coal output, which have pushed domestic prices up resulting in higher prices elsewhere. Spot steam coal prices increased significantly, from around USD 45/tonne (t) in January 2016 up to over USD 90/t in November 2016 (thermal coal imports to Europe). Likewise, with regard to coking coal, the increase was even higher, quadrupling from USD 77/t in January 2016 up to over USD 300/t in November 2016 (coking coal exports from Australia).

Producers' discipline delivered significant cost reductions. Some external factors, such as low oil prices and currency depreciation in major exporters, also played a role in decreasing costs, but the main driver was the cost-cut strategy of most producers forced to do so by the sustained price decrease. Production of high cost mines was suspended or abandoned; productivity was increased through better utilisation of human resources and assets; some bottlenecks in the production chain were eliminated, output from operating mines was maximised and the work of contractors optimised. Higher prices, combined with a healthier, more competitive coal industry, have somehow changed the landscape. Overall perspectives on the coal industry are now much firmer than just one year ago although reasonable doubts persist on the sustainability of current prices, given that climate pressure continues and air pollution is a serious issue which will shape policies in China, India and other emerging countries.

Coal is still a Chinese tale

Regardless of whether its demand has peaked or not, China will be the largest user of coal by far through the outlook period. In our forecast, coal demand in China decreases through 2018 with a slight recovery afterwards, but coal demand in 2021 will be below 2013 levels. The increase post-2018 is mostly driven by coal demand for power, as power demand recovers a pace of growth closer to historical trends after a couple of years of very low increases, while hydro growth will decline at the end of the outlook period. Decline in steel and cement production also pushes coal demand down. The only sector with strong growth through the period is chemicals, with over 100 Mt, despite some slowdown of coal-to-gas and coal-to-liquids projects. Despite this decline, China will still account for almost 50% of global coal demand, over 45% of coal production, and more than 10% of seaborne trade.

China still moves the (coal) world. As has been the most recurrent message of the *Medium-Term Coal Market Report* in the past years, coal market dynamics are determined by developments in China. This proved to be true once again in 2016, when the measures taken by the Chinese government to curb oversupply, in particular the reduction of working days, gave rise to a spike in coal prices, further exacerbated by disruptions in Australia and Indonesia, which led prices to unexpected levels. But changes arrive very quickly in China: only a few months after the new policy was introduced, the government softened it to cool down coal markets. Import volumes have mirrored the price trajectory as the price increase and coal production cuts in China produced an unexpected increase of imports to China. The subsequent result is that macroeconomic development and policies in China shape coal demand and supply, with implications elsewhere.

Volatility and uncertainty for major importers

Import growth in traditional major importers disappears. Despite declining coal production in Europe through the outlook period, coal imports will also decline significantly owing to a drop in coal demand that is even steeper than that in production. In mature economies in Asia, the growth of coal imports will be curtailed in long-standing big importers, such as Japan and Korea (and, to a lesser extent, Chinese Taipei); sluggish power demand growth; and increasing renewable and nuclear electricity output, despite upside potential coming from new coal power projects and, in particular in Japan, uncertainty about future nuclear production.

Imports will balance out Chinese and Indian markets. In China and India, the forecast will be defined by the volatility of import volumes and by uncertainty about the evolution of volumes through the period. India is somewhat similar to China, although on a smaller scale. Both are big producers and consumers where imports play a balancing role, but, given their size, changes in imports have an impact on the global market, as was proved in 2016 by the changing trend of Chinese imports. We expect steam coal imports to India to grow slightly, with a clear downside potential because the Indian government is trying hard to reduce coal imports, although price, quality and geography make this difficult. The potential to increase domestic coking coal production is, however, limited as a result of quality issues; hence, coking coal imports to India will increase based on growth in steel production.

But some smaller importers will give imports a boost, thus offsetting declines in Europe and elsewhere. As expected, Viet Nam became a net importer after being a considerable exporter for a few years. We expect growing imports to Viet Nam based on the power generation capacity under construction and sound economic growth. A smaller but significant boost is expected in Pakistan and in other countries such as Turkey, Malaysia and Morocco that are already importers. Overall, seaborne trade will grow at the end of the period although volumes by 2021 will still be below 2013 levels, with coking coal volumes slightly higher and thermal volumes lower. Big upside potential resides in Egypt and Bangladesh, where the announced coal power developments combined would require well over 50 Mt of imports; given the slow progress, if any, of most of those projects, our projections do not foresee them in operation in our timeframe.

Quo vadis, coal?

Coal mining investment is drying up. In an environment of low and decreasing prices, capital expenditures (capex) are minimised and very few projects move ahead: this has been the case for the last few years. Current higher prices will create larger output from operating mines or from part of the idled or suspended capacity that may be put into operation. However, as the current price spike is linked more to Chinese policies to cut oversupply than to sustained strong demand, and structural overcapacity remains in China, we expect prices to decline from the today’s levels and to recover a bit by the end of the outlook period, and hence, we do not see the momentum building for new mining investment. The situation is different in coal power generation, where investments have been stable during the last few years, despite the increasing restrictions from many European and North American banks and institutions on coal financing.

Despite the Paris Agreement, there is no major trigger for carbon capture and storage (CCS). To fulfil the goals of the Paris Climate Agreement, CCS will be key, as the Agreement establishes more ambitious temperature targets while providing a framework for climate action that extends beyond 2050, namely to achieve a balance between man-made emissions by sources and removals by sinks of greenhouse gases in the second half of the century. This should provide momentum for refocusing efforts on CCS. Yet, one year on from Paris there is little indication that governments are acting to enforce limits on CO_2 emissions that will allow investment in CCS to happen. Without CCS or technological innovation to use captured CO_2 for commercial purposes, coal must be virtually eliminated if Paris targets are to be met, which can be challenging in power generation and even more so in industrial applications.

1. RECENT TRENDS IN DEMAND AND SUPPLY

Key findings

- **In 2015, global coal consumption declined for the first time this century.**[1] Total global demand decreased by 2.7%, from 5 588 million tonnes of coal-equivalent (Mtce) in 2014 to 5 440 Mtce in 2015. Coal continued to be the second-largest primary energy source, accounting for 29% of global energy consumption.

- **Consumption of both steam coal and metallurgical (met) coal declined in 2015.**[2] Steam coal demand decreased by 3% in 2015, and metallurgical coal (met coal) demand was 1.3% lower than in 2014 (from 1086 million tonnes [Mt] to 1071 Mt). An increasing percentage of coal-based power generation was replaced by generation from other fuels. The decline in met coal consumption, however, is largely due to lower steel production resulting from macroeconomic developments in the People's Republic of China (hereafter "China").

- **For the first time since 1981, Chinese coal consumption has declined for two consecutive years.** Chinese consumption was 3.4% lower in 2015 than in 2014, a drop of 99 Mtce (from 2 896 Mtce to 2 797 Mtce). Coal-fired generation in China decreased again in 2015 owing to reduced power demand and diversification away from coal. Coal use in the steel and cement sectors also decreased.

- **India has become the second-largest coal consumer in the world, surpassing the United States.**[3] Total coal consumption increased by 2.7% in 2015 compared with 2014. Nevertheless, the increase was considerably lower than the average growth rate of 7.5% over the last decade. Growth in coal-fired generation was lower than in the previous year as a result of lower growth in total power generation.

- **The United States had the largest decline in coal demand ever observed in the country's history.** Consumption dropped a dramatic 15%, from 839 Mt in 2014 to 713 Mt in 2015. Owing to lower than expected prices for natural gas in 2015 (average Henry Hub spot prices were USD 2.62 per million British thermal units [MBtu]), a large amount of coal-based generation was displaced by gas. Thus, coal's share in the US electricity mix dropped from 39% in 2014 to a record low of 34% in 2015. In April 2015, electricity generation from natural gas (93 terawatt hours [TWh]) exceeded generation from coal (89 TWh) for the first time in the United States.

- **Global coal production decreased for the second year in a row.** The significant declines in production in China (-3.1%), the United States (-11.5%) and Indonesia (-3.2%) have contributed to the global decline in supply. Lower demand and low prices have created an overall unfavourable situation for companies. Having reached their cost-cutting limits, numerous producers in the United States have declared bankruptcy after continued losses.

- **Despite the challenging environment, production in India and Australia increased in 2015.** Australian producers, who have continued cutting costs, were successful in increasing production by 4.1% despite harsh market conditions. Growth in Indian production (+5.1%) was strongly driven by the government's push to meet the growing domestic demand.

[1] The first decline of the century in terms of volume was observed in 2014.

[2] Definitions of coal types and other technical terms can be found in IEA (2011), Box 1 and IEA (2012), Box 1.

[3] India had become the second-largest consumer in 2014 by volume, but not in terms of energy content.

Demand

Coal was the second-largest primary energy source in 2015 after oil, accounting for about 29% of total primary energy consumption in the world. Global coal demand decreased in 2015 for the first time in this century. In physical tonnes, global coal demand decreased by 2.6% (-206 Mt) compared with 2014. The 3.4% decrease in Chinese demand (-134 Mt) combined with the 15% decrease (-126 Mt) in the United States were the major contributors to this global reduction. Although coal demand increased in India by 2.7% (+24 Mt) and in the Russian Federation (hereafter "Russia") by 8.9% (+18 Mt), it was not enough to offset the significant reductions of China and the United States. Overall, coal demand decreased substantially in 2015 in Organisation for Economic Co-operation and Development (OECD) countries (-129 Mt) and in OECD non-member economies (-78 Mt).

Table 1.1 Coal demand overview

	Total coal demand (Mt) 2014	Total coal demand (Mt) 2015*	Absolute growth (Mt) 2014-15	Relative growth (%) 2014-15	CAGR (% per year) 2005-14	Share (%) 2015
China	3 897	3 764	-134	-3.4%	6.7%	48.8%
India	889	912	24	2.7%	7.5%	11.8%
United States	839	713**	-126	-15.0%	-1.8%	9.3%
Germany	239	239	-	0.2%	-0.4%	3.1%
Russia	201	219	18	8.9%	-0.8%	2.8%
European Union	699	691	-8	-1.1%	-1.6%	9.0%
OECD	2 099	1 970	-129	-6.1%	-1.0%	25.6%
Non-OECD	5 813	5 736	-78	-1.3%	5.6%	74.4%
World	**7 912**	**7 706**	**-206**	**-2.6%**	**3.3%**	**100.0%**

* Estimate.
** 725 Mt in accordance with the EIA.
Notes: CAGR = compound annual growth rate. Differences in totals are due to rounding.
Source: IEA (2016a), *Coal Information 2016*, www.iea.org/statistics/.

Chinese demand constituted about 49% of global coal demand in 2015. Demand growth in China has been particularly strong in the past decade, making China the main driver of international coal markets. However, coal consumption in China declined in 2014 for the first time in the decade and declined further in 2015. The rebalancing of the Chinese economy and the associated decrease in coal-based generation in the electricity sector are the main reasons for this significant decline.

India retained its position in 2015 as the second-largest coal consumer (following China) in terms of physical tonnes. Moreover, for the first time it became the second-largest consumer in terms of coal in energy content, as forecast in previous editions of the *Medium-Term Coal Market Report.* Even so, India's growth in coal consumption in 2015 was significantly lower than in the previous year. This deceleration can be attributed to the lower growth rate of coal-fired electricity generation in 2015, in addition to the slowdown in the Indian steel and cement sectors.

Coal consumption in the United States has declined by an average of 1.8% annually during the last decade. In recent years, the abundance of inexpensive shale gas – combined with coal-fired generating capacity retirements – has resulted in natural gas gradually replacing coal in electricity generation. In 2015, electricity generation from coal fell behind generation from natural gas for the first time, driving the share of coal in electricity generation to record lows. As a result, the United States experienced its greatest ever decline in coal demand.

Total global hard coal consumption decreased by 194 Mt in 2015 to an estimated 6 899 Mt, a 2.7% decrease from the previous year. Demand in OECD countries decreased by 7% (-108 Mt), whereas non-OECD demand decreased by 1.6% (-87 Mt). Similarly, global demand for steam coal decreased by 2.9% (-178 Mt). OECD countries again had a larger decline of 8% (-108 Mt), compared with the 1.5% (-70 Mt) decrease in OECD non-member economies. Total global demand for met coal also declined in 2015, dropping by 1.6% (-16.4 Mt) to an estimated 1 072 Mt. Met coal demand in OECD countries stayed roughly the same, while non-OECD demand fell by 1.9% (-16.7 Mt). The main reason for this decrease was the decline in steel production in China.

Total global lignite consumption in 2015 decreased by 1.4% (-11.8 Mt) to approximately 807 Mt. OECD demand declined by 3.7% (-20.7 Mt), whereas non-OECD demand increased by 3.4% (+9 Mt). Note that lignite consumption in OECD countries is almost twice that of non-OECD countries. In contrast, non-OECD countries greatly dominate in steam coal consumption. Lignite accounts for about 10% of total global coal consumption in terms of weight; due to the low calorific value of lignite compared with hard coal, this share decreases to 5% when energy content is considered.

Box 1.1 The continuous movement of coal to Asia

From the beginning of the Industrial Revolution in the 18th century and well up to the end of the 20th century, the industrialised nations of Europe and North America have been the main consumers of coal in the world. However, the situation changed rapidly when coal began to play a major role in the emerging economies of Asia. Whereas 3.7 billion people lived in Asia in 2000, by 2015 this number had reached 4.4 billion; in the same period the population of North America increased from 490 million to 573 million. In contrast, growth in the European population was very subtle, increasing merely from 730 million to 738 million. Asia accounted for 33% of the world gross domestic product (GDP) in 2000, but by 2015 its share had increased to 45% – China’s share alone increased from 7% to an impressive 17%. China eventually overtook Japan in 2009 to become the second-largest economy in the world and the largest in Asia.

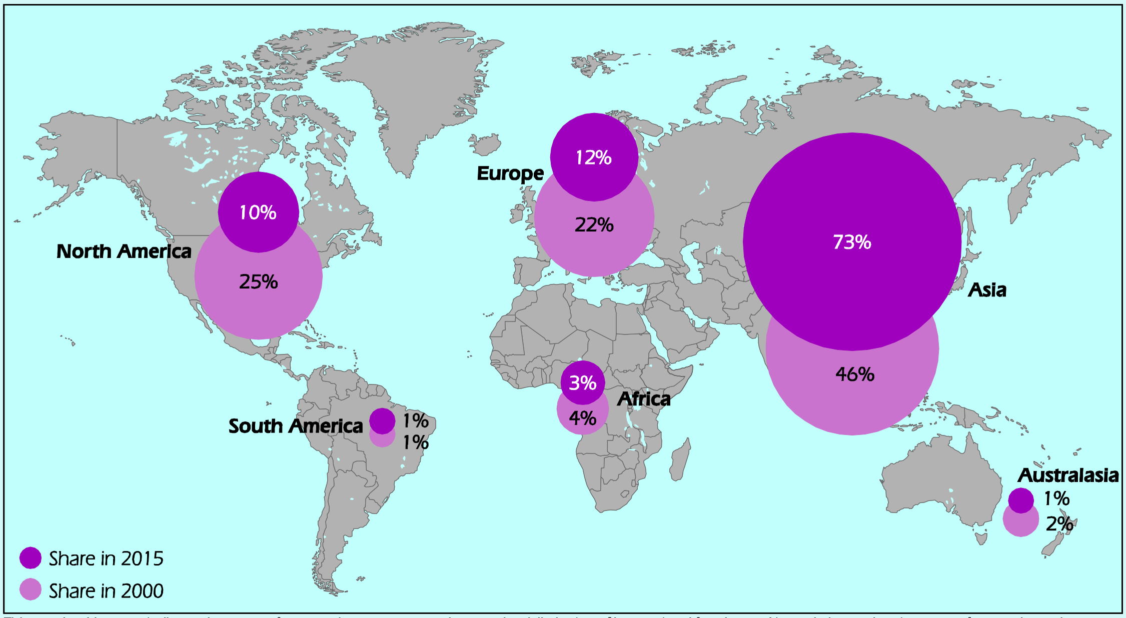
From 1990, the Chinese economy grew by a staggering 10% each year on average, the strident pace of industrialisation generating an enormous demand for energy and a huge appetite for coal. Similarly, growth and industrialisation in India and Association of Southeast Asian Nations (ASEAN) countries resulted in larger amounts of coal consumed in these countries. At the same time, however, in developed economies the share of heavy industries has gradually declined, and the less energy-intensive services sector has become the major component. This change in GDP composition, together with environmental and climate change policies as well as increasingly available alternative energy sources, has caused coal’s share in the energy supply to decrease in Europe and North America.

In Map 1.1, individual continent shares of global coal consumption are illustrated for the years 2000 and 2015. While North America accounted for 25% and Europe for 22% of global coal consumption in 2000, these shares had dropped to 10% (North America) and 12% (Europe) by 2015. For instance, 760 Mtce of coal were consumed in the United States in 2000, but only 523 Mtce in 2015. Coal consumption similarly dropped in the largest coal-consuming countries in Europe: Germany (from 115 Mtce to 112 Mtce), Poland (83 Mtce to 75 Mtce) and the United Kingdom (52 Mtce to 33 Mtce). In contrast, it rose dramatically in China, from 966 Mtce to 2 797 Mtce, and in India, from 206 Mtce to 553 Mtce. This tremendous growth in China and India, combined with increasing coal demand in other Asian countries,

Box 1.1 The continuous movement of coal to Asia (continued)

has resulted in Asia's share in global coal consumption increasing from 46% in 2000 to a dominating 73% by 2015. The story of coal markets has increasingly become an Asian story in the last decade.

Map 1.1 Share of global coal consumption by continent, 2000 and 2015



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

Source: IEA (2016a), *Coal Information 2016*, www.iea.org/statistics/.

OECD demand trends

Total OECD hard coal consumption in 2015 was 1 430 Mt – a 7% decrease (-108 Mt) from 2014 – accounting for a 20.8% share in global hard coal consumption, and continuing the negative trend of the past decade. OECD Americas in particular reduced hard coal consumption, with a 14% (-118 Mt) drop. The decline in OECD Europe was small, at roughly 1% (-3 Mt); in contrast, hard coal demand in OECD Asia Oceania increased by 3.4% (+13 Mt).

In OECD Americas and OECD Europe, the drop in hard coal demand includes declines in both steam and met coal. The consumption of steam coal in OECD Americas decreased by 14.5% (-116 Mt) and met coal by 6.4% (-2 Mt). Steam coal demand in OECD Europe decreased by 0.6% (-2 Mt), while the decline in met coal demand was higher in relative terms, a decrease of 2% (-1 Mt). In OECD Asia Oceania, however, steam coal consumption increased by 3.3% (+10 Mt) and met coal by 3.8% (+3 Mt).

The largest hard coal consumer in the OECD in 2015 was the United States, followed distantly by Japan and Korea. In 2015, hard coal demand in the United States decreased significantly, by 15% (-116 Mt), whereas it increased slightly in Japan by 2% (+3 Mt)[4] and in Korea by 3% (+4 Mt). Japan and Korea are also the largest met coal consumers in the OECD region. In 2015, met coal consumption in Japan fell slightly,

[4] Given the decline in coal power generation in Japan in 2015, demand increase must be related to statistical issues on stock accounts.

by 1.5% (-0.8 Mt) but grew significantly in Korea, by 12% (+4 Mt).[5] Australian hard coal consumption increased for the first time since 2009, by a considerable 11% (+5.6 Mt). This trend reversal is strongly driven by an increasing share of coal-fired generation in the Australian power supply mix.

Table 1.2 Hard coal and lignite consumption in selected OECD member countries (Mt)

Country	Hard coal			Lignite		
	2014	2015*	Growth	2014	2015*	Growth
Australia	50.9	56.5	11%	60.5	65.7	9%
Austria	3.2	3.8	19%	-	-	-
Belgium	4.5	4.1	-9%	-	-	-
Canada	33.7	30.2	-10%	8.0	10.4	30%
Chile	11.6	11.9	3%	-	-	-
Czech Republic	7.4	7.6	3%	38.3	38.1	-1%
Denmark	4.0	2.9	-28%	-	-	-
Finland	4.6	3.8	-17%	-	-	-
France	13.2	12.3	-7%	0.2	0.1	-50%
Germany	61.7	62.0	-	177.0	177.2	-
Greece	0.3	0.2	-33%	51.9	48.1	-7%
Hungary	1.5	1.5	-	9.2	9.2	-
Ireland	2.0	2.3	15%	-	-	-
Israel**	10.9	10.6	-3%	-	-	-
Italy	20.1	19.6	-2%	-	-	-
Japan	188.1	191.5	2%	-	-	-
Korea	134.9	139.3	3%	-	-	-
Mexico	21.9	23.2	6%	0.6	0.6	-
Netherlands	14.6	18.1	24%	-	-	-
New Zealand	2.6	2.5	-4%	0.3	0.3	-
Poland	73.6	71.7	-3%	63.8	63.0	-1%
Portugal	4.5	5.5	22%	-	-	-
Slovak Republic	3.8	3.7	-3%	2.5	2.6	4%
Spain	21.4	23.8	11%	-	-	-
Turkey	32.2	36.8	14%	64.7	50.5	-22%
United Kingdom	48.1	38.0	-21%	-	-	-
United States	762.6	646.4	-15%	76.5	66.9	-13%

* Estimate.
** The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD and/or the International Energy Agency (IEA) is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.
Source: IEA (2016), *Coal Information 2016*, www.iea.org/statistics/.

OECD lignite demand dropped by 3.7% (-21 Mt) to 536 Mt in 2015, and the OECD share of lignite consumption globally dropped from 68% in 2014 to 66%. The main contributors were Turkey, with a 22% (-14 Mt) decrease in lignite consumption, and the United States with a 12.5% (-10 Mt) decrease.

Power sector

Total coal-based power generation in OECD countries decreased by 7.5% (-260 TWh) to an estimated 3 201 TWh in 2015, falling behind the 2014 generation of 3 461 TWh – itself a record low in the last decade. The share of coal in the overall OECD electricity mix fell from 32.1% to 29.7%, while at the same time total electricity generation stayed essentially flat, from 10 784 TWh to 10 762 TWh.

[5] There are some issues with coking coal statistics for Korea, currently under review.

The main contributor to the decrease in total coal-based generation in OECD countries was the United States, with a sharp decline of 14% (-239 TWh) compared with 2014. Furthermore, the share of coal in the US electricity mix dropped from 39% in 2014 to a record low of 34% in 2015. The increased supply of natural gas and corresponding decrease in natural gas prices[6] have pushed a significant amount of coal-based generation out of the market. In April 2015, for the first time, electricity generation from natural gas (93 TWh) was higher than coal-based generation (89 TWh) in the United States. Installed capacity of coal-based generation was 277 gigawatts (GW) in December 2015 – a significant drop from 291 GW at the end of 2014, with many more closures in 2016. Pressure from environmental regulations has also contributed to this decrease, and Mercury and Air Toxics Standards (MATS) initiated by the Environmental Protection Agency (EPA), despite having been rejected by the Supreme Court in June 2015, have also resulted in early closure of some coal power plants. (The MATS were subsequently revised by the EPA to comply with the Supreme Court ruling and are currently in place.)

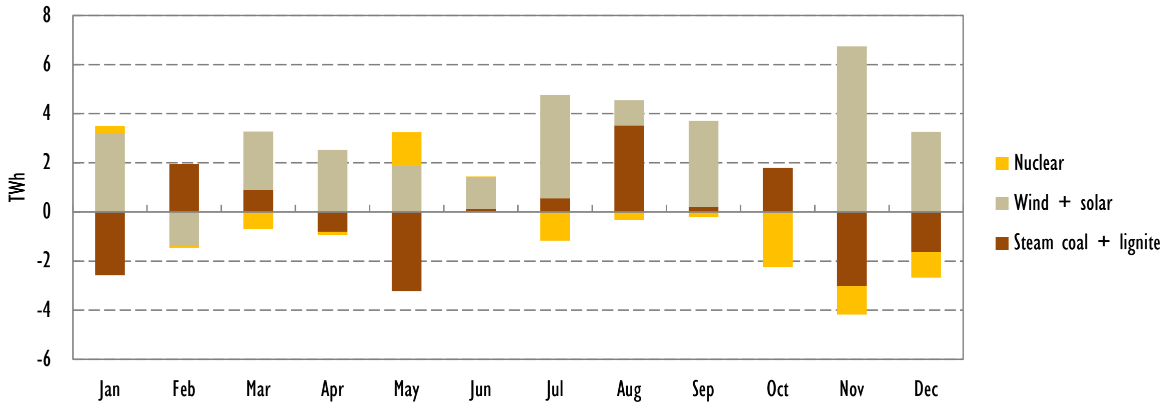
In OECD Europe, the largest drop in coal-based electricity generation occurred in the United Kingdom, where it decreased by 25% (-25 TWh) to 77 TWh in 2015. The share of coal in the electricity generation mix was 23% in 2015, significantly lower than the 2014 share of 30%. The difference was made up mainly through substituting with generation from renewables and, to some extent, from nuclear power. This trend has continued in the first quarter of 2016 and the share of coal has consequently dropped to a record low of 16%. Ironbridge power plant (360 megawatts [MW]) was closed in November 2015 due to the Large Combustion Plant Directive, and the Industrial Emissions Directive has since resulted in closure of several power plants that found it uneconomic to upgrade to comply with the directive: Unit 4 of Ferrybridge (500 MW) and the Longannet (2 240 MW) power stations closed in March 2016. Additionally, the increase of carbon price support (CPS) in April 2014 from GBP 4.94 per tonne of CO_2 (tCO_2) to GBP 9.55/tCO_2, followed by its rise to GBP 18.08/tCO_2 in April 2015, has further increased pressure on coal-based generation in the United Kingdom.

Coal-fired generation in the Netherlands increased 9 TWh in 2015, a 27% increase from 2014. One of the major contributors was the commissioning of the new Eemshaven coal power plant (1 560 MW). In Spain, coal-based generation also increased significantly in 2015, by 21% (+9 TWh); this was mainly the result of reduced hydro generation due to lower precipitation. Belgium, however, has joined the list of countries that do not have any coal-based electricity generation. Belgium's last remaining coal power plant, Langerlo (556 MW), was closed in March 2016. The plant was sold in early 2016 by E.ON to German Pellets, and there are plans to convert it to a biomass plant using imported wood pellets as fuel.

In Germany, coal-based electricity generation remained basically unchanged, decreasing only slightly by 1% (-3 TWh) from 2014. Figure 1.1 provides the monthly year-on-year (2014-15) development of electricity produced from nuclear energy, coal and renewables (wind + solar) in Germany. Although decommissioning of the nuclear power plant Grafenrheinfeld (1 345 MW) in June 2015 would normally have resulted in increased coal-based generation (since the baseload generation lacking would have to be provided by coal power plants), the dramatic increase in generation from renewables in 2015 more than made up for this difference.

[6] Henry Hub prices averaged USD 4.37/MBtu in 2014 and USD 2.62/MBtu in 2015.

Figure 1.1 Monthly year-on-year difference in electricity generation from coal, nuclear and renewable sources in Germany, 2014-15



Coal-based generation in Turkey decreased by 4% (-3 TWh) in 2015 as a result of greatly reduced lignite consumption (lignite production was 30% lower than in 2014 in terms of tonnes). There are several reasons for this decrease: in May 2014 the Soma mine disaster occurred, in which 301 people lost their lives due to an underground explosion and ensuing fire; the disaster is classified as the work accident with the highest number of fatalities in the history of the Republic of Turkey. The Ermenek mine disaster followed shortly afterwards in October 2014, in which 18 miners lost their lives. New legislation issued after the disasters shortened the weekly working hours of underground miners, and also extended holidays and doubled the minimum wage for miners. This raised the production costs of lignite mines considerably, and increased mine inspections resulted in temporary closure of some mines. The substantial production losses from the Soma and Ermenek mine disasters further contributed to the drastic drop in Turkish lignite production.

In 2015, coal consumption in Poland was 58.3 Mt of thermal coal, 4% lower than the 61 Mt of 2014, and 13.4 Mt of coking coal, a 6% increase from 12.6 Mt in 2014. Lignite demand remained roughly the same in 2015, with a consumption of 63 Mt. Coal power generation, the main driver of coal demand, increased from 128 TWh in 2014 to 130 TWh in 2015 (76.6 TWh from steam coal and 53 TWh from lignite). During the same period, generation from wind and solar grew 40% from 7.7 TWh to 10.9 TWh. Coke production, the second-largest use of coal in Poland, decreased slightly from 9.9 Mt in 2014 to 9.8 Mt in 2015. The overall trend has not changed significantly since coal demand remains stable in different sectors: for example, the amount of electricity generated from coal in Poland is almost the same in 2015 as it was in 1995.

In OECD Asia Oceania, coal-based power generation increased slightly, by about 4 TWh. The main contributor was Australia, with a 4% (+6 TWh) increase from 2014. Total power generation stayed roughly the same, while the share of coal in the Australian generation mix rose from 61% to 64%. In contrast, the hydropower share dropped from 7.4% to 5.6%. One of the main reasons for increased coal power generation was the lacking rainfall in 2015, which reduced hydropower output. Tasmania was hit especially hard by the drought and had to import increasing amounts of lignite-produced power from Victoria.[7] Additionally, the newly commissioned liquefied natural gas (LNG) plant in

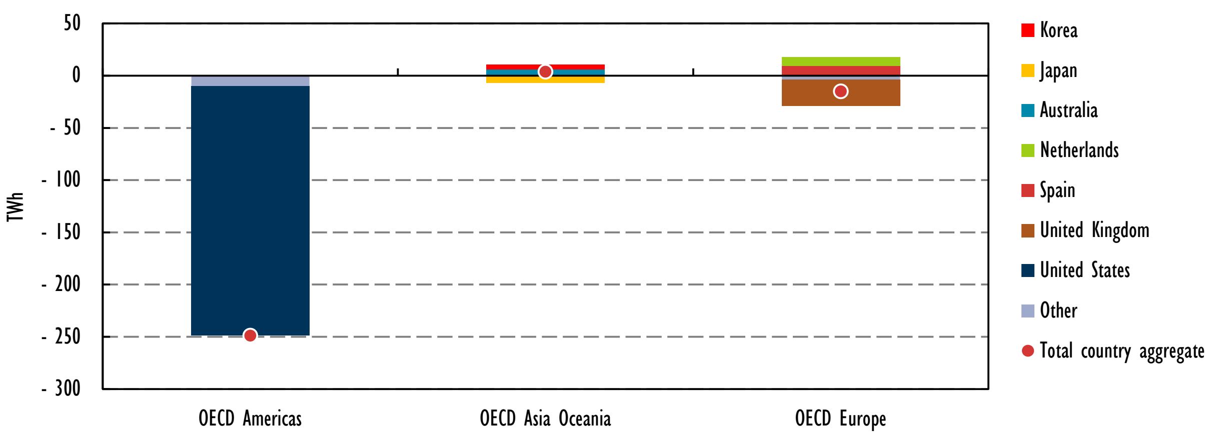
[7] The Basslink HVDC cable connecting Tasmania and Victoria was disconnected in December 2015 due to a fault, eventually causing a drop in Victorian lignite-fired power generation.

Gladstone – with its additional power demand – provoked an increase in thermal coal-fired generation in Queensland. It should be pointed out that the repeal of the carbon tax in July 2014 had already increased the competitiveness of coal-fired power plants in general.

In Korea, coal-based power generation increased by 2% (+4.5 TWh) from 2014, while total generation remained more or less constant. Generation from liquefied natural gas (LNG) decreased by 9% (-9 TWh), with the difference being largely offset by nuclear power and, to some extent, coal-fired power. Consequently, the share of coal in the generation mix increased slightly, from 42% to 43%.

Coal-based generation in Japan decreased by 2% (-6 TWh) in 2015. The main reason was a decline in total electricity consumption, which was 2.6% (-27 TWh) lower than in 2014. The restart of the Sendai nuclear power plant (1 780 MW) in 2015, which mainly replaced LNG but also displaced some coal power generation, made some contribution although the plant only became operational during the second half of 2015, so the effect was not pronounced.[8]

Figure 1.2 Absolute changes in coal-based electricity generation in OECD countries, 2014-15



Source: IEA (2016a), *Coal Information 2016,* www.iea.org/statistics/.

Non-power sector

Total coal consumption of OECD countries in 2015 in the non-power sector is estimated at 279 Mtce, 2% lower than in 2014. Within the non-power sector, the iron and steel industry is the largest coal-consuming industry. The amount of coal consumed in the iron and steel sector in 2015 decreased by 4.5% to an estimated 137 Mtce. In the cement industry, the second-largest industrial coal-consuming sector, consumption was an estimated 31.7 Mtce in 2015, slightly (0.7%) higher than in 2014.

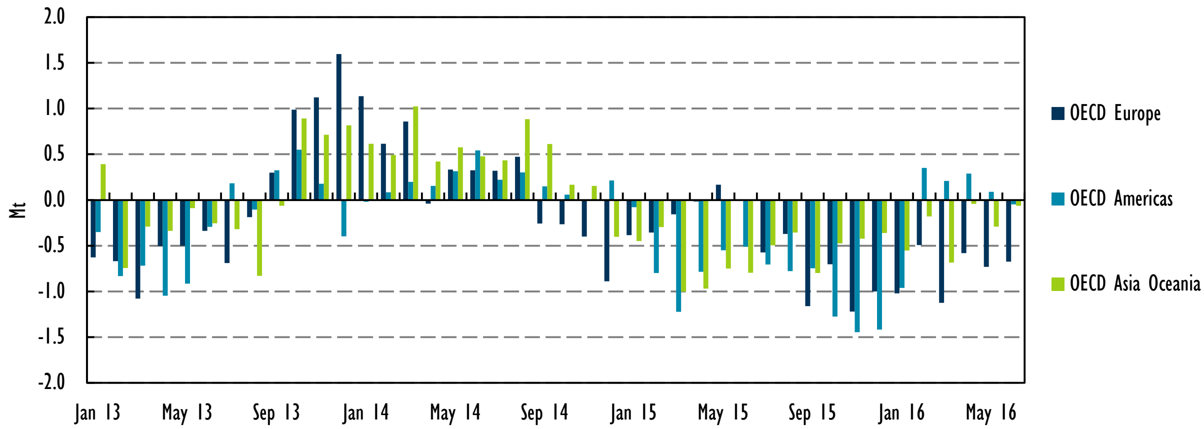
Met coal demand in the OECD region decreased overall in 2015, with the exception of Korea. Statistics show an increase of 4 Mt in met coal consumption despite the decrease in Korean steel and pig iron production.[9] In Figure 1.3, monthly year-on-year differences in steel production in OECD countries are plotted. It is clear that OECD steel production was lower in 2015 than in 2014; during

[8] Unit 1 restarted operations in August 2015, and Unit 2 in October 2015.

[9] There are some issues with coking coal statistics for Korea, currently under review.

the first quarter of 2016, however, OECD Americas produced more than in the first quarter of 2015. Steel production in OECD Europe was significantly lower than in the previous year because of more affordable Chinese and Russian imports, but in August 2016 the European Commission imposed anti-dumping tariffs on cold-rolled steel from China and Russia.

Figure 1.3 Monthly year-on-year difference in crude steel production in OECD member countries, 2013-16



Source: World Steel Association (various years), *Crude Steel Production*, www.worldsteel.org/statistics/crude-steel-production0.html.

OECD non-member demand trends

Total hard coal consumption in OECD non-member economies in 2015 was 5 464 Mt, accounting for 79% of global hard coal demand. This demand was 1.6% (-87 Mt) lower than in 2014, and after the slight drop in 2014,[10] this is only the second time in this century that non-OECD hard coal demand has decreased. Additionally, steam coal demand decreased by 1.5% (-70 Mt) and met coal demand by 1.9% (-16.7 Mt) in OECD non-member economies.

Chinese hard coal consumption fell for the second year in a row, decreasing by 3.4% (-133.5 Mt) to 3 764 Mt in 2015. This is the first time since 1981 that coal consumption in China has fallen for two consecutive years. As in 2014, China was the largest contributor to the non-OECD decrease in hard coal demand. Ongoing rebalancing of the Chinese economy is the main factor in this decrease: in 2013, the services sector accounted for 46.1% of GDP, exceeding industry's share (43.9%) for the first time. The services sector share has continued to grow, accounting for 50.5% of GDP at the end of 2015. China's efforts to improve energy efficiency have had a significant impact on China's energy demand profile. Energy efficiency levels across China's end-use sectors (residential heating, transport, and industry) improved by over 19% on average between 2000 and 2015.[11] Moreover, although electricity demand grew by 0.5% in 2015, coal-based generation decreased due to an increase of other sources. This decrease in coal-based electricity generation, declining demand in the non-power sector, and contraction in the coal-intensive steel and cement sectors have all contributed to the overall decrease in hard coal demand in China. Nevertheless, China still remains the largest hard coal consumer in the world by far. Its share in total non-OECD demand has, however, decreased from 70% to 69%.

[10] Only in physical volumes. In energy content, 2014 coal demand in non-OECD economies actually increased.

[11] A comprehensive analysis of energy efficiency improvement in China can be found in IEA (2016b).

Although Indian hard coal consumption increased by 3.3% (+27 Mt) in 2015, this increase was very low compared with the 7.5% average annual growth rate of the last decade. This lower rate of increase can be mainly attributed to overall slower growth in coal-based electricity generation. Furthermore, growth in the coal-intensive steel and cement sectors in India was also lower in 2015 than in 2014.

Table 1.3 Hard coal and lignite consumption in selected OECD non-member economies (Mt)

Country	Hard coal			Lignite		
	2014	2015*	Growth	2014	2015*	Growth
Bosnia and Herzegovina	7.4	7.6	3%	5.6	6.1	9%
Brazil	27.7	27.4	-1%	-	-	-
Bulgaria	1.8	1.5	-17%	31.4	35.8	14%
Chinese Taipei	66.3	65.8	-1%	-	-	-
Colombia	7.4	8.3	12%	-	-	-
DPR of Korea	15.3	16.3	7%	-	-	-
India	841.7	869.1	3%	47.0	43.2	-8%
Indonesia	79.0	90.9	15%	-	-	-
Kazakhstan	78.6	76.0	-3%	4.2	4.0	-5%
Kosovo	-	-	-	7.2	8.2	14%
Malaysia	24.2	26.8	11%	-	-	-
Mongolia	2.5	4.0	60%	6.2	5.7	-8%
China[12]	3 897.2	3 763.7	-3.4%	-	-	-
Philippines	19.9	20.8	5%	-	-	-
Romania	0.8	0.8	-	25.4	25.4	-
Russian Federation	133.8	148.0	11%	67.3	70.9	5%
Serbia	0.2	0.2	-	30.7	38.1	24%
South Africa	192.9	176.0	-9%	-	-	-
Thailand	17.5	23.0	31%	18.5	15.2	-18%
Ukraine	60.6	46.0	-24%	-	-	-
Viet Nam	34.3	41.6	21%	-	-	-

* Estimate.
Source: IEA (2016a), *Coal Information 2016*, www.iea.org/statistics

Lignite consumption in OECD non-member economies increased by 3.4% (+9 Mt), to 271 Mt in 2015. The largest increase, compared with 2014, was in Serbia, where lignite consumption rose by 24% (+7.4 Mt). It should be noted, however, that lignite consumption was exceptionally low in Serbia the previous year due to floods in May 2014 that disrupted lignite production; the increase in 2015 should therefore be interpreted as a return to normal. After Serbia, the two other main contributors to the rise in non-OECD demand were Bulgaria, with increased consumption of 14% (+4.4 Mt), and Russia with 5% (+3.6 Mt). The largest decreases in demand were in India, with an 8% decrease (-3.7 Mt), and Thailand, with a decrease of 18% (-3.3 Mt).

Power sector

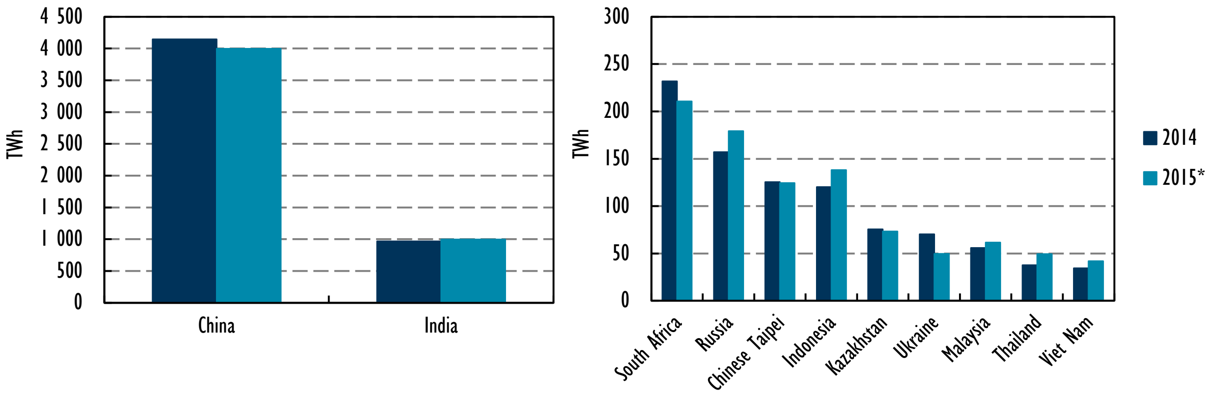
Following a decade of sustained growth, coal-based electricity generation in China decreased for the second year in a row in 2015. An estimated 3 765 TWh of electricity was generated from coal in 2015, 4.7% (-186 TWh) less than in 2014. The overall reduction in electricity generation as well as

[12] China consumes lignite, although it is not reported as such

substantially increased generation from hydro and nuclear resulted in less electricity produced by coal power plants. In 2015, 52 GW of net coal-based generation capacity was added in China; in contrast, full-load hours for coal power plants dropped from 4 778 hours in 2014 to 4 364 hours in 2015.

It is clear that building new coal-based capacity regardless of continually declining utilisation rates has created a state of overcapacity in the Chinese coal generation fleet. Nevertheless, a significant number of new coal-fired power plants, with an aggregate capacity of over 150 GW, are currently under construction (for more detailed discussion see Box 3.2).

Figure 1.4 Coal-based electricity generation in selected OECD non-member economies



* Estimate.
Source: IEA (2016a), *Coal Information 2016*, www.iea.org/statistics/.

India generated an estimated 998 TWh of electricity from coal in 2015, a 3.3% increase from 2014; this is significantly lower than the 11% growth of the previous year. Growth of total power demand also slowed in 2015 compared with 2014, dropping from 8.4% to 5.6%.

In South Africa, coal-based generation is estimated to have fallen by 9% (-21 TWh) from 2014. There are several reasons for this decrease: first, the Hendrina power plant had to halt operations for a month due to disputes with its supplier. Second, a large portion of the generation fleet (about 11 GW) was unavailable because of unplanned shortages, which could be attributed to insufficient maintenance in the last decade. Third, there was a delay in commissioning the Medupi[13] and Kusile power plants. As a result, load shedding measures were taken in 2015 in South Africa, as they had been in 2014.

Coal-based generation in Russia increased by an estimated 14% (+22 TWh) in 2015, mainly due to low hydropower generation, since overall power demand stayed roughly the same. In contrast, Ukrainian coal-based generation decreased by an estimated 29% (-21 TWh), the main contributors to this decline being the economic recession in the country and the conflict in East Ukraine. Increased power generation from nuclear has also replaced a significant amount of coal-based generation.

Coal power generation is estimated to have increased in Indonesia by 15% (+18 TWh), in Viet Nam by 21% (+7.4 TWh) and in Thailand by 32% (+12 TWh) in 2015. The main reason for these increases is the growth of coal-based generation capacity in Viet Nam and Indonesia, coupled with firm power demand growth in the three countries.

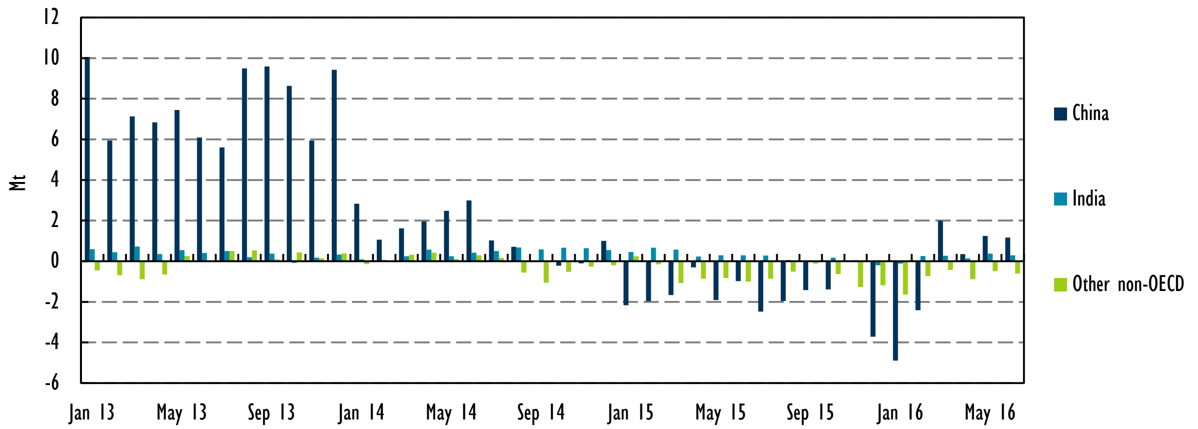
[13] The first unit of Medupi (794 MW) was commissioned in August 2015.

Non-power sector

In 2015, non-power coal consumption in OECD non-member economies was an estimated 1 829 Mtce. While this represents a 2% decrease from 2014, it accounts for 45% of total coal consumption in OECD non-member countries. The steel industry, with an estimated consumption of 711 Mtce, was the largest non-power consumer at 39% of non-power coal consumption, followed by the cement industry, with an estimated 308 Mtce consumption and a share of 17%.

Coal consumption by the Chinese non-power sector decreased by 4% in 2015 to an estimated 1 356 Mtce, accounting for 74% of total non-power coal consumption in OECD non-member economies. Furthermore, China continued to be the largest steel and cement producer in the world in 2015, despite the fall by 2.4% of Chinese steel output (to 796 Mt), for which an estimated 515 Mtce of coal was consumed. Steel prices rose significantly in the first half of 2016, mainly driven by government policy measures to balance production overcapacity. As a result, steel production increased during the first half of 2016 in China compared with 2015. There were also several capacity additions in the coal-to-gas and coal-to-liquids sectors in 2015: the Yili coal-to-gas plant reached an annual capacity of 1.3 billion cubic metres per year (bcm/yr), up from 0.5 bcm in 2014. The Yankuang company's Yulin coal-to-liquids plant became operational with a capacity of 1 million tonnes per annum (Mtpa); its production in 2015 amounted to 0.2 Mtpa.

Figure 1.5 Monthly year-on-year change in crude steel production in OECD non-members, 2013-16



Source: World Steel Association (various years), *Crude Steel Production*, www.worldsteel.org/statistics/crude-steel-production0.html.

Chinese cement production decreased by 5% to 2.35 billion tonnes in 2015; the required coal input for this volume of cement production is estimated at 233 Mtce. In addition to smaller cement producers, the Chinese cement industry is largely made up of approximately 800 integrated cement plants with a total production capacity of almost 1.5 billion metric tonnes (Bt). However, given the overcapacity in the cement sector in China, several regions such as Beijing and Tianjin have banned commissioning of new cement plants. After a declining trend in 2015, cement production in China increased in the first half of 2016 compared with 2015, driven by a 20% increase in infrastructure investment.

Indian non-power coal consumption increased by 3% in 2015 to an estimated 187 Mtce, driven by the steel industry as the largest coal-consuming non-power industry. India was also the only country among the ten largest steel-producing countries in the world to have growth in steel output in 2015.

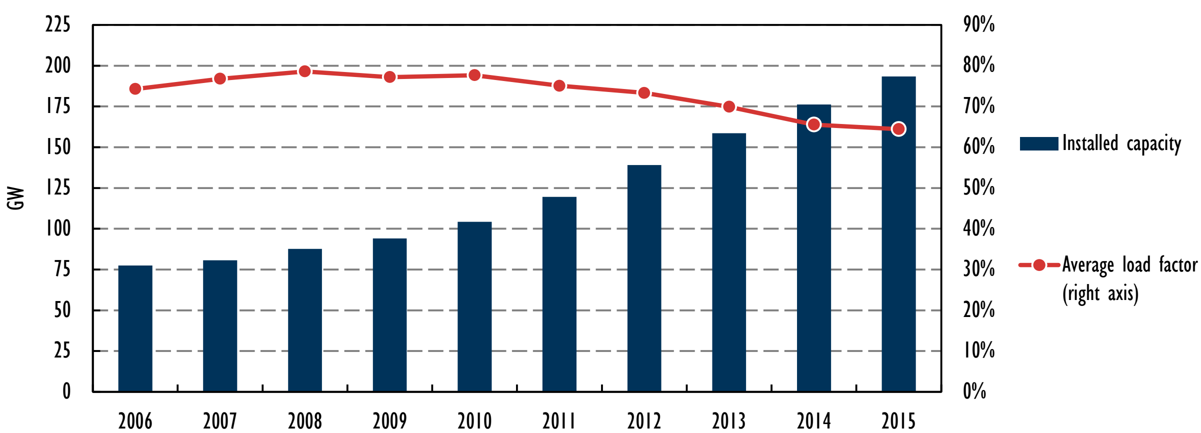
With this 3% increase, an estimated 90.5 Mtce of coal was consumed for steel production in 2015. Coal consumption for cement production in India similarly increased by 4%, to an estimated 29.2 Mtce in 2015. Despite growth in the housing and infrastructure sectors, the Indian cement industry currently suffers from overcapacity. Nevertheless, supply and demand are expected to balance in the near future as capacity expansion slows and government spending for housing and infrastructure projects increases.

In the Middle East, an increase in overall non-power coal consumption has been observed, in particular in the cement sector. In Egypt, the use of coal in the power sector and in industry was approved in 2014; various cement kilns switched from gas to coal as a result. As of May 2015, 90% of cement plants in Egypt had announced plans for a coal-fuel switch. Several cement kilns in Jordan have also started using coal, thereby increasing the demand for coal in that country as well.

Regional focus: India

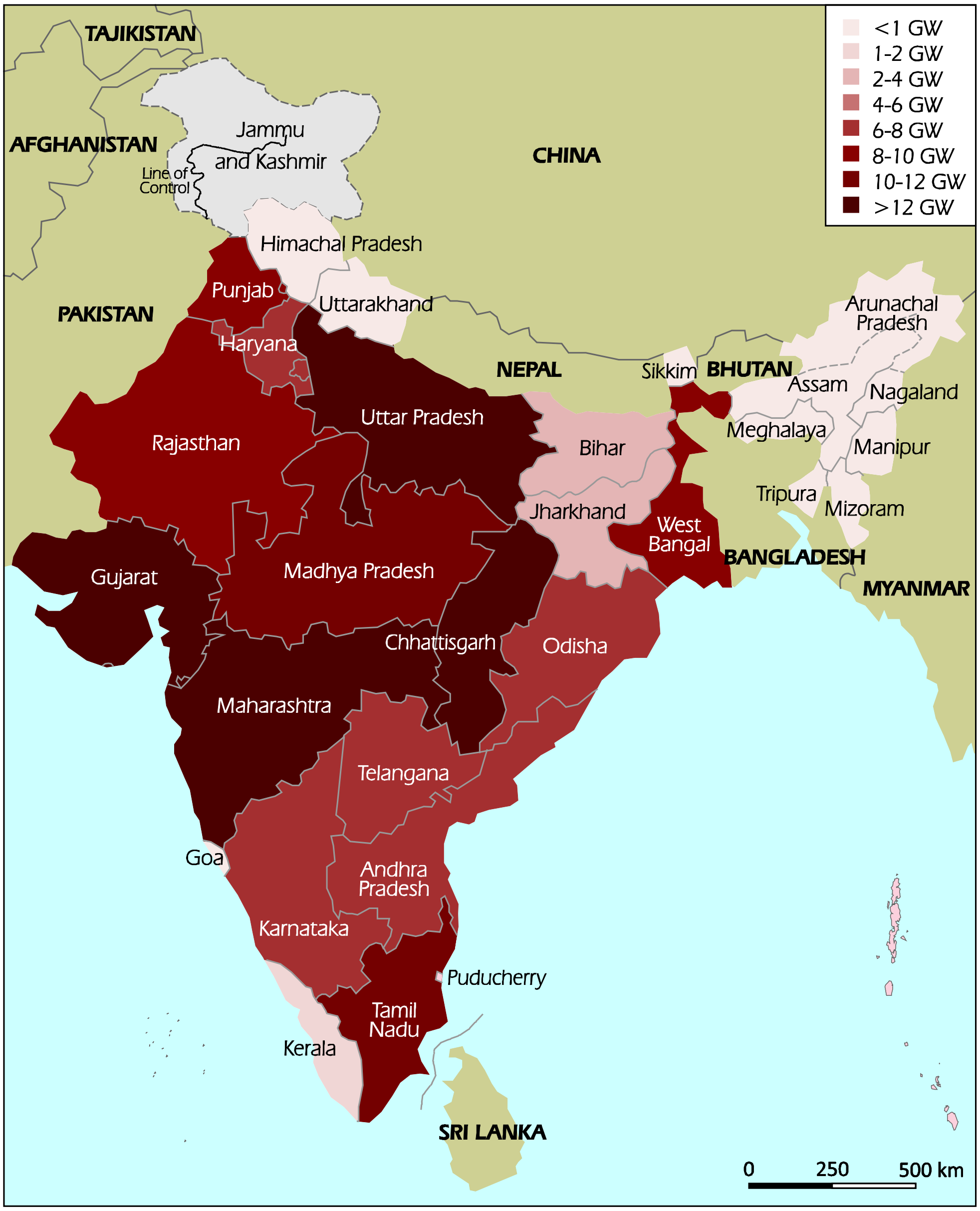
India, which became the second-largest coal consumer in the world in 2014 in volumes (in 2015 in energy), continued to increase its coal demand by a further 2.7% in 2015 to 889 Mt. By far the largest coal consumer in India is the electricity sector, with a 66% share of total coal consumption, followed by steel production, which accounted for 16% of total Indian coal demand. India is the third-largest steel producer in the world, but it has a larger share of direct reduced iron (DRI) in its steel production than other countries and is therefore less dependent on coking coal. The third-largest coal consumer is the cement industry, with a share of 5% in 2015.

Figure 1.6 Installed capacity and average load factors of coal power plants in India, 2006-15



The installed capacity of coal-fired power plants in India has increased rapidly in recent years, reaching 193 GW at the end of 2015. About 31% of this capacity is owned and operated by individual state-owned utilities, while 26% belongs to the central government-owned National Thermal Power Corporation (NTPC). India's private sector, with a remarkable 33% share, owns the largest share of total generation capacity. The remaining 10% is made up of captive power plants; some companies, such as Adani Power and Tata Power, own significant capacity and are private independent power producers (IPPs). Coal-fired power plants are located close to the demand centres: almost 40% of total installed capacity is located in the western region, while 25% is in the north.

Map 1.2 Geographical distribution of coal-fired power plants in India



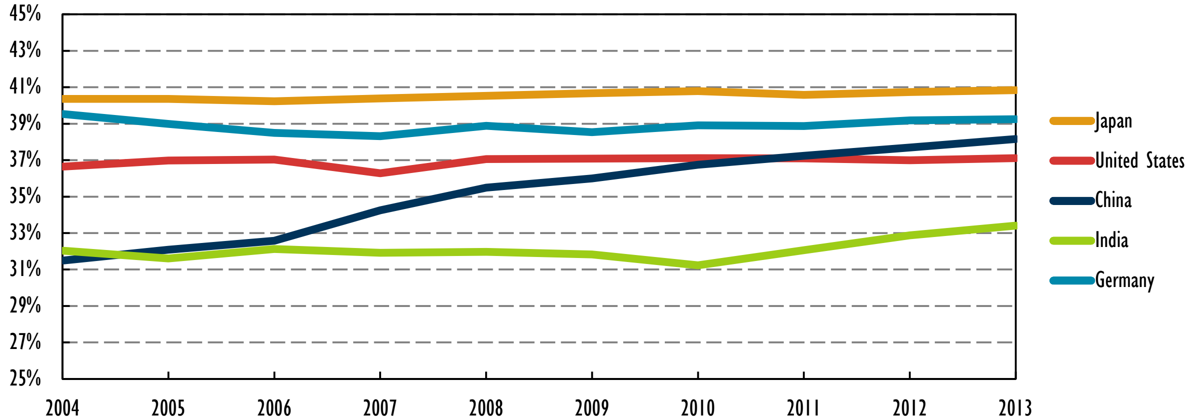
The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA. Black dotted line approximately represents the Line of Control in Jammu and Kashmir agreed upon by India and Pakistan. The final status of Jammu and Kashmir has not yet been agreed upon by the parties.

The Indian coal-fired power plant fleet is relatively young: over 120 GW of capacity has been installed since 2002 and is therefore less than 15 years old. However, despite being relatively new, the average efficiencies of Indian coal-fired power plants are low compared with international standards. As shown in Figure 1.7, the average efficiency of Indian coal-fired power plants (32%) is comparable to that of China's plants in 2006. After 2006, China invested heavily in modern supercritical and ultra-supercritical power plants, which led to a strong increase in average efficiency that allowed it to surpass even highly industrialised Western countries such as the United

States. In India, however, until 2010 almost the entire coal-fired power plant fleet was based on subcritical technology. After 2010, investment in supercritical power plants has increased, leading to the upward trend in average efficiency depicted in Figure 1.7. Nevertheless, at around 33%, average efficiency in India remains low.

In addition to reliance on subcritical technology, other factors limit the efficiency of coal-fired power plants in India. The first constraint is the low quality of domestic coal, largely being used by Indian power plants. Indian coal typically has a low calorific value, in the range of 2 500 kilocalories per kilogramme (kcal/kg) to 5 000 kcal/kg. Additionally, the ash content is high – up to 50%. This high ash content not only limits power plant efficiency, owing to poor heat transfer in the boiler, but it also leads to higher maintenance requirements because corrosion is greater and there are more residues from the burning process to be removed.

Figure 1.7 Average efficiency of coal-fired power plants in different countries, 2004-13



Another limiting factor for thermal power plant efficiency is the high temperature in India's tropical regions, given that efficiency improves with lower cooling temperatures in the condenser. Efficiency in India therefore cannot match that in Europe even with the same steam conditions. Finally, the efficiency of the coal-fired power plant fleet is affected by low load factors, which lead to part-load efficiency losses. Despite an electricity shortage and an all-time high in power demand, utilisation of coal-fired power plants in India has declined in recent years to 65% in 2015 (see Figure 1.6). The reasons for this decline are domestic coal production shortages, railway bottlenecks and the financial distress of power distribution companies, which limit their ability to purchase power from the generators.

Supply

In 2015, global coal supply decreased for the second year in a row, by 2.8% (-221 Mt) to an estimated 7 709 Mt. The main contributors to this decrease were China (3.1% or -113 Mt), the United States (11.5% or -105 Mt) and Indonesia (-3.2%). Although coal production increased in India by 5.1% (+34 Mt) and in Australia by 4.1% (+20 Mt), the increase in supply in both countries was less than that of the previous year. The average growth rate of global coal supply in the last decade was 3.4%.

Table 1.4 Coal production overview

	Total coal supply (Mt) 2014	Total coal supply (Mt) 2015*	Absolute growth (Mt) 2014-15	Relative growth (%) 2014-15	CAGR (% per year) 2005-14	Share (%) 2015
China	3 640	3 527	-113	-3.1%	5.7%	45.8%
United States	918	813	-105	-11.5%	-1.0%	10.5%
India	657	691	34	5.1%	4.8%	9.0%
Australia	489	509	20	4.1%	3.4%	6.6%
Indonesia	485	469	-15	-3.2%	12.9%	6.1%
OECD	2 020	1 900	-120	-5.9%	-0.3%	24.7%
Non-OECD	5 909	5 808	-101	-1.7%	5.1%	75.3%
World	**7 930**	**7 709**	**-221**	**-2.8%**	**3.4%**	**100.0%**

* Estimate.
Note: Differences in totals are due to rounding.
Source: IEA (2016a), *Coal Information 2016*, www.iea.org/statistics.

OECD supply trends

Coal production in OECD member countries was 1 900 Mt in 2015, which is 5.9% (-120 Mt) lower than in 2014. The 6.9% (-101 Mt) decrease in hard coal production was the main cause of the decline in supply. Steam coal production decreased by 7.8% (-91 Mt), and met coal production decreased by 3.4% (-10.5 Mt). OECD lignite production decreased in 2015 as well, to 531 Mt, 3.5% (-19 Mt) lower than in 2014.

Hard coal production in OECD Americas decreased drastically by 12% (-108 Mt) in 2015, with the United States contributing significantly (-97 Mt) to this decline. The major reasons were low international prices and falling demand in the power sector owing to more affordable gas and to environmental regulations. Within the United States, production decreased in the Central Appalachian Basin in particular because of the high mining costs in this region. Production in the Northern Appalachian Basin, the Rocky Mountain region and the Powder River Basin was also low compared with 2014. The Illinois Basin, however, was affected much less by overall adverse market conditions: as a result of its lower production and freight costs, it remains a favourable source of coal destined for export markets. Moreover, due to MATS in the United States and the Large Combustion Plant Directive (LCPD) in Europe, coal power plants have installed scrubbers, thus increasing the market for high sulphur coal from the Illinois Basin.

Hard coal output in OECD Asia Oceania increased in 2015 by 3.3% (+14.5 Mt) from the previous year, largely as a result of the 3.5% growth in Australian supply (+15 Mt). While steam coal production in Australia increased by 1.7% (+4.3 Mt), met coal supply grew more substantially, having increased by 6% (+10.8 Mt). In Australia a few new mines started operation in 2015, while other mines closed. The Maules Creek mine of Whitehaven Coal was officially commissioned in February 2015, although production started in 2014. Anglo American's new Grosvenor underground mine also started production in the first quarter of 2015, achieving a production rate of 8.5 Mtpa. The Isaac Plains mine, which was bought by Stanmore Coal, restarted operations in April 2016. During the same period, the Crinum underground mine, producer of met coal, was closed after having reached the end of its commercial lifespan; Glencore, too, closed its Newlands Northern underground mine for the same reason. The Baralaba thermal coal mine was placed under care and maintenance, as was the Wongawili met coal mine, although the latter is expected to restart operations in the third quarter of 2016. The Russel Vale Colliery met coal mine was closed as a result of low market prices.

The production of hard coal in OECD Europe decreased by 6.7% (-7.4 Mt). The United Kingdom suffered the largest decrease, with a 27% (-3.1 Mt) drop in production, mainly driven by the April 2015 hike in the carbon floor. Production in Germany also declined substantially, by 20% (-1.7 Mt), fully in line with the country's long-term plan to phase out hard coal mining by 2018.

Table 1.5 Hard coal and lignite production among selected OECD member countries (Mt)

Country	Hard coal			Lignite		
	2014	2015*	Growth	2014	2015*	Growth
Australia	428	443	4%	61	65	7%
Canada	61	51	-16%	8	10	25%
Czech Republic	9	8	-11%	38	38	-
Germany	8	7	-13%	178	178	-
Greece	-	-	-	51	46	-10%
Hungary	-	-	-	10	9	-10%
Korea	2	2	-	-	-	-
Mexico	15	15	-	1	1	-
New Zealand	4	3	-25%	-	-	-
Norway	2	1	-50%	-	-	-
Poland	73	73	-	64	63	-2%
Slovak Republic	-	-	-	2	2	-
Spain	4	3	-25%	-	-	-
Turkey	3	3	-	63	50	-21%
United Kingdom	12	9	-25%	-	-	-
United States	846	749	-11%	72	64	-11%

* Estimate.
Source: IEA (2016a), *Coal Information 2016*, www.iea.org/statistics/.

The decrease in OECD lignite production in 2015 was caused largely by the 4.4% (-18 Mt) reduction in OECD Europe. Turkey, with a decrease of 24% (-12 Mt), had the single largest decline in lignite production among OECD Europe countries; Greece also had a significant decrease of 10% (-4.6 Mt). Lignite production in OECD Americas declined overall, by 7% (-5.7 Mt) although, while production in the United States decreased by 12% (-8 Mt), Canada's production increased 23% (+2.4 Mt). In contrast to global OECD lignite production, production in OECD Asia Oceania increased by 8% (+4.8 Mt).

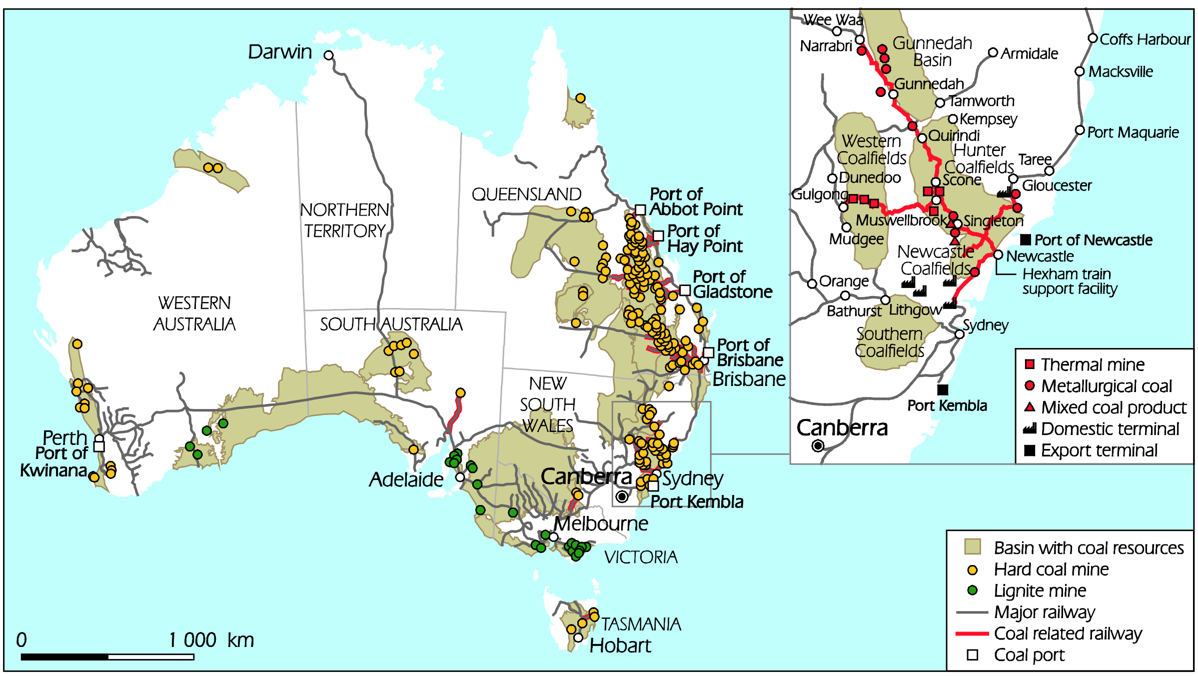
In 2015, hard coal production in Poland was 72 Mt, unchanged from 2014 production levels. Thermal coal production was 59 Mt (compared with 60 Mt in 2014), and coking coal production was 13 Mt (compared with 12 Mt in 2014). Despite production levels remaining stable, the Polish coal sector has changed radically during 2015 and 2016.

After some years of severe losses, driven by low coal prices and under-investment as well as overstaffing and poor management, Kompania Weglowa, the largest hard coal producer in Europe, was set to be liquidated in April 2016. Instead, the Polish government restructured the company, whose assets were acquired by several Polish companies. Most of them – 11 mines with 27 Mtpa of combined capacity – were transferred to a new company called Polska Grupa Gornicza, which is now the largest hard coal producer in Europe. The remaining three mines were transferred to Tauron Wydiobicye (Brzeszcze mine), Weglokoks Kraj (Bobrek-Piekary mine) and Spolka Restrukturyzacji Kopaln (Makoszowy mine). In addition, the state-owned Enea Group took control of LW Bogdanka, the only mine in the Lublin Coal Basin and the lowest-cost coal mine in Poland by far. The purpose of this strategy is to make the mines profitable in two to three years through materialisation of needed investment and improved management. Higher coal prices in 2016 give some margin to the restructuring process, but are not expected to be enough to return the coal mines to profitability without proper investment and management. Prospects for the other Polish companies are more positive: both the remaining public sector – Jastrzebska Spolka Weglowa, the main coking coal producer; Katowicki Holding Weglowy; and Tauron Wydobycie – and the small private sector (PG Silesia, EKO-plus and ZG Siltech) can be profitable at current prices.

Regional focus: Australia

Australia is the fourth-largest coal producer in the world and contains the fourth-largest coal resources, following the United States, Russia and China. Total Australian accessible economic resources amount to 56 gigatonnes (Gt) for hard coal and 34 Gt for lignite. At 2015 production levels of roughly 443 Mt of hard coal and 65 Mt of lignite per year, these resources will be sufficient for approximately another 125 years of hard coal production and 525 years of lignite production. In 2015, Australian producers increased hard coal output by 3.5% and lignite output by 7.9%, compared with 2014. Met coal production in particular increased significantly: by 11 Mt (+6%) in 2015 for a total amount of 191 Mt.

Map 1.3 Australian mining areas and major export terminals



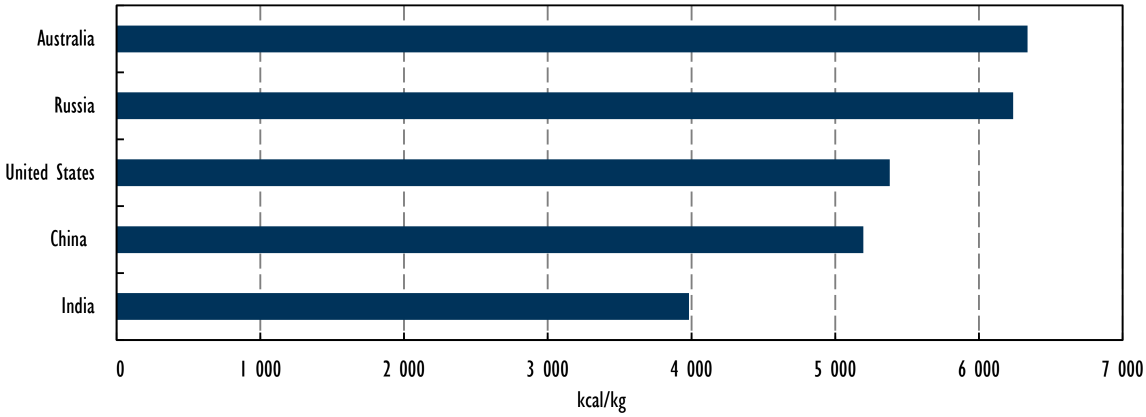
This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

Coal is produced in all six Australian states, but over 95% of hard coal production takes place in Queensland and New South Wales. The most important basins are the Bowen Basin in Queensland and the Sydney Basin in New South Wales. Additional significant hard coal resources are located in the Surat, Clarence-Moreton, Galilee and Gunnedah basins (Map 1.3). The Galilee Basin has gained much attention in recent years because several large-scale greenfield mining projects are planned in this region, which is estimated to contain around 6 Gt of coal. Lignite production, however, is located mainly in the Gippsland Basin in Victoria. Roughly 80% of Australian coal is produced in surface-based mines, which is a high share compared with the rest of the world. The large majority of Australian underground mines use longwall mining.

Most of Australian hard coal is destined for export markets. In 2015, 81% of total steam coal production and 98% of total met coal production were sold on the international market. The main export destinations for Australian coal are Japan, China and Korea. Australian coal for domestic and export markets is transported through a network of roads, railways and ports. The Hunter Valley Coal Chain in New South Wales is the largest export operation in the world. It serves approximately 35 coal mines with coal haulage distances of up to 380 kilometres with more than 31 points for loading coal onto trains. The coal is transported to domestic coal-fired power plants in the Hunter Region and to the Port of Newcastle, which is the largest coal-exporting harbour in the world. Other major coal-related railway systems are the Blackwater Rail Corridor, the Gonyella Coal Rail Corridor, the Moura Coal Rail Corridor, the Newlands Rail Corridor and the South-West Rail Corridor. Other important ports used to export coal are Abbot Point, Hay Point, Gladstone, Kembla and Kwinana. The majority of these ports are located on the Australian east coast, either in Queensland or New South Wales. The only coal-exporting port on the west coast is Kwinana, which stopped exporting coal in 2014 after the export agreement with Griffin Coal was terminated.

The five largest coal producers in Australia are Glencore, BHP Billiton, Rio Tinto, Peabody Energy and Anglo American, which together accounted for roughly 53% of total Australian met coal production and 50% of total thermal production in 2015. The largest producer in 2015 was Glencore with an output of 56 Mt of thermal coal and 10 Mt of met coal. The largest producer of met coal in 2015 was BHP Billiton, accounting for 43 Mt of Australian met coal production.

Figure 1.8 Average energy content of coal production by country, 2015



Australian coal is typically of high quality. Thermal coal has a high-energy and low-ash content that makes it suitable for modern high-efficiency low-emissions coal-based power generation technologies. Additionally, the sulphur, selenium, mercury and other trace elements contained are low by international standards. Large amounts of Australian coal are also suitable as metallurgical coal and can be used to produce coke. In 2015, 43% (191 Mt) of total Australian hard coal production was met coal, which makes Australia the second-largest producer of met coal in the world after China. The average calorific value of Australian hard coal production in 2015 was

6 339 kcal/kg, which is considerably higher than that of all other global coal producers. The energy content of Australian hard coal exports was even higher, at 6 458 kcal/kg.

OECD non-member supply trends

In 2015, total coal production in OECD non-member economies dropped by 1.7% (-101 Mt) to an estimated 5 808 Mt. Hard coal production decreased 2% (-111 Mt); steam coal output was 2% (-100 Mt) lower, and met coal was similarly 1.5% (-11 Mt) lower than in 2014. Lignite production, in contrast, increased by 3.9% (+10.5 Mt).

Table 1.6 Ownership status of the 21 largest coal mining companies in China and their production volumes, 2015

	Company	Owned by	Production 2015 (Mt)	Share
1	Shenhua Group Co., Ltd.	National government	430	12%
2	Datong Coal Mine Group Co., Ltd.	Shanxi province	175	5%
3	China National Coal Group Co., Ltd.	National government	170	5%
4	Shangdong Energy Group Co., Ltd.	Shandong province	135	4%
5	Shaanxi Coal & Chemical Industry Group Co., Ltd.	Shaanxi province	125	4%
6	Shanxi Coking Coal Group Co., Ltd.	Shanxi province	105	3%
7	Yankuang Group Co., Ltd.	Shandong province	110	3%
8	Jizhong Energy Group Co., Ltd.	Hebei province	100	3%
9	Henan Coal Chemical Industry Group Co., Ltd.	Henan province	100	3%
10	Kailuan (Group) Co., Ltd.	Hebei province	90	3%
11	Shanxi Lu'an Mining (Group) Co., Ltd.	Shanxi province	85	2%
12	Yangquan Coal Industry (Group) Co., Ltd.	Shanxi province	75	2%
13	Shanxi Jincheng Anthracite Mining Group Co., Ltd.	Shanxi province	70	2%
14	Jinneng Group Co., Ltd.	Shanxi province	70	2%
15	Huainan Mining (Group) Co., Ltd.	Anhui province	65	2%
16	Heilongjiang Longmay Mining Holding Group Co., Ltd.	Heilongjiang province	50	1%
17	Inner Mongolia Pingzhuang Coal Industry Co., Ltd.	National government	45	1%
18	Huolinhe Opencut Coal Industry of Inner Mongolia	National government	45	1%
19	Huadian Coal Industry Group Co., Ltd.	National government	45	1%
20	China Pingmei Shenma Energy & Chemical Group	Henan province	40	1%
21	Inner Mongolia Yitai Group Co., Ltd.	Private company	40	1%
	TOTAL 21 largest companies		2 170	62%

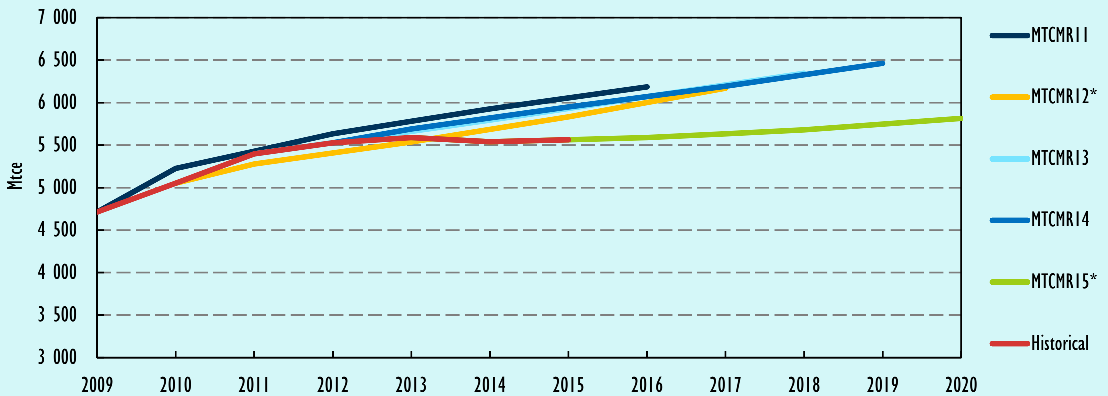
Hard coal production in China decreased by 3.2% (-113 Mt) in 2015; steam coal output fell 3.5% (-104 Mt); and met coal output fell 1.4% (-8.7 Mt). Lower coal demand in 2015, the supply glut and resulting low prices were the main factors contributing to this decline. As a result of the plunge in prices, numerous smaller Chinese mines stopped operating. In addition, China strengthened measures against illegal mining. At the end of 2015, China's National Energy Administration announced that no new coal mine projects would be approved for the next three years and that more than 1 000 smaller coal mines would be shut down. A further significant development in China was the reduction of working days for coal miners in April 2016, from 330 to 276 per year. The new regulation aims to decrease oversupply in the Chinese supply, and in the longer term, overcapacity.

The high concentration of public ownership in coal mining companies in China deserves special attention. Table 1.6 lists the 21 largest Chinese coal mining companies in terms of production: companies owned by the national government and by provincial governments dominate the supply side with respect to production. Thus, the largest-producing privately owned company ranks only 21st. This dominance of publicly owned companies on the supply side makes it more likely that government regulations for mining are more rapidly adjusted depending on the needs of the sector in the face of changing market conditions.

Box 1.2 *Medium-Term Coal Market Report* demand forecasts five years later

Since the first *Medium-Term Coal Market Report (MTCMR)* of 2011, global coal markets have changed significantly. These changes are reflected in the deviations between the forecasts – published in the first five editions of the report (2011 to 2015) – and real-world events. Figure 1.9 compares the forecasts for global coal demand with the actual historical development of coal consumption. Until 2013, real-world demand growth was roughly in line with the forecasts; since 2013, however, historical data shows that actual coal demand has been below forecast demand. In 2015, the difference was roughly 500 Mtce.

Figure 1.9 Comparison of global coal demand forecasts with real world developments



* In these reports two alternative scenarios were presented; the base case scenarios are considered here.

The deviation between forecast and actual coal demand can be attributed to various factors: the first is the stronger-than-expected slowdown and rebalancing of the Chinese economy. Ongoing restructuring in China involves moving away from heavy industry-based growth towards a more service- and consumption-oriented economy.

The second important development that has been underestimated in past forecasts is the decoupling of electricity demand growth from GDP growth in OECD economies since the financial crisis of 2008. Figure 1.10 depicts the historical development of electricity demand in OECD Americas as well as OECD Europe and compares it with the development expected, given the relationship between economic growth and electricity demand before the financial crisis. It is evident that, based on historical GDP elasticities, continued growth in electricity demand would have been anticipated after recovery from the financial crisis. The gap would have theoretically been filled by generation from coal and gas, but it was expected to be covered predominantly by coal-based generation, given the cost advantage of coal.

Instead, electricity demand stagnated in OECD Americas and even declined in OECD Europe, which suggests a fundamental change in the correlation between economic growth and electricity in developed

Box 1.2 *Medium-Term Coal Market Report* demand forecasts five years later (continued)

Western economies, a change that has led to an overestimation of coal use in power production in OECD countries. Additionally, gas prices in the United States have declined more sharply than expected because of the strong increase in domestic shale gas production that led to higher coal-to-gas fuel switching in US power production, thereby reducing coal consumption even further.

Figure 1.10 Electricity demand in OECD economies after the financial crisis

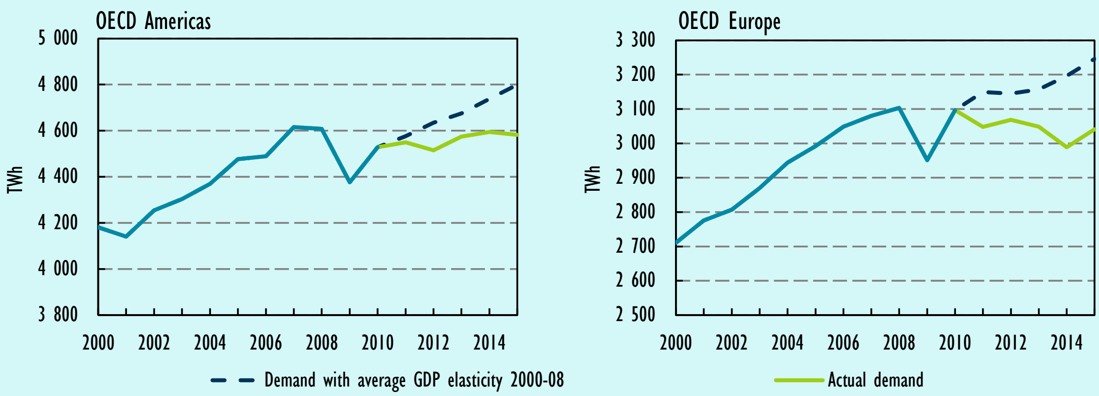
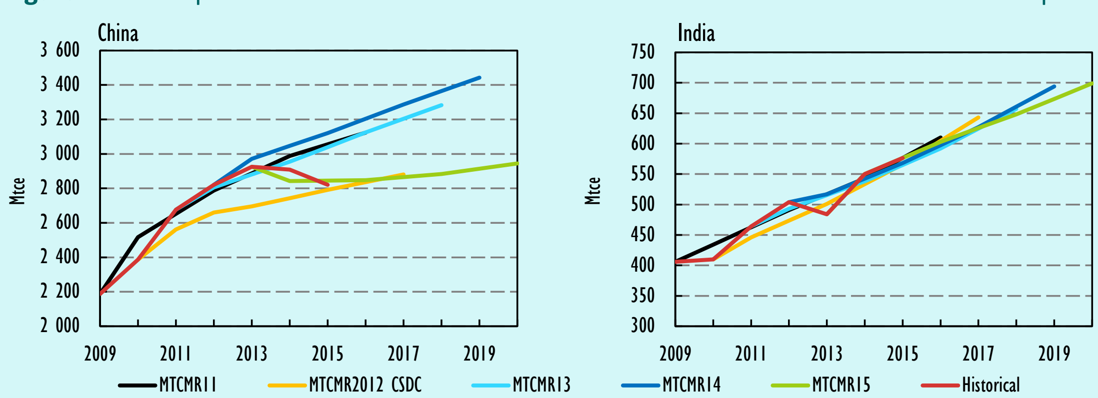


Figure 1.11 provides a comparison of *MTCMR* forecast results with real-world developments for China and India. The *MTCMR* generally matches Chinese demand, but the big slowdown and rebalancing in 2014 was missed, except in the Chinese Slow-Down Case (CSDC) in the 2012 report, which predicted actual consumption in 2015 based on lower economic growth and energy intensity than in the Base Case. Nevertheless, general overestimation in the base case scenarios can be attributed to several factors. Because industry and infrastructure are highly dependent on coal, rebalancing of the Chinese economy has had important implications for the development of coal demand. In 2015 especially, the slowdown in industrial value-added growth was stronger than expected, and the actual economic growth rate was below International Monetary Fund (IMF) forecasts. Another factor is that declining energy demand growth affects coal consumption directly and to a much greater extent because the Chinese energy supply from zero, near zero or very low variable cost sources (hydro, wind, solar and nuclear) is almost inelastic and gas availability is an issue; coal therefore is the marginal supplier and absorbs almost all the energy difference.

Figure 1.11 Comparison of Chinese and Indian coal demand forecasts with real-world developments



For India, *MTCMR* demand forecasts successfully captured strong growth in coal consumption (Figure 1.11). Coal consumption has increased significantly in recent years as strong economic growth and increasing electrification in rural areas have driven coal-fired electricity production.

Indian hard coal production increased by 6% (+39 Mt) in 2015, with most of this increase due to higher steam coal production since met coal output remained unchanged for the most part. Supply growth in 2015 was, however, lower than in 2014; lower demand was primarily responsible. Furthermore, delays in forest and environment clearances, as well as the rainy season in 2015, limited the growth in coal production.

Hard coal production in South Africa was down 3% (-8.4 Mt) in 2015 from 2014, owing largely to decreased demand in the power sector. The New Clydesdale Colliery (NCC) underground mine of Australian-listed Universal Coal became operational in September 2016. It is expected to produce 0.9 Mt of export thermal coal annually.

Indonesian hard coal production decreased by 3.3% (-15 Mt). The main reason for the decrease was lower demand in China in 2015, which is the largest market for Indonesian exports; lower prices hit hard to Indonesian producers. In 2015, the government further pursued efforts to reduce illegal mining by tasking the Corruption Eradication Commission (KPK) with investigating 4 000 miners.

Hard coal production in Ukraine decreased drastically by over 40% (-23 Mt). Ongoing conflict in the eastern region of the country, as well as coal-based power being replaced by nuclear in electricity generation, greatly contributed to the decline in production. In contrast, Russian hard coal production grew 4.5% (+12 Mt). Steam coal production, which increased by 10 Mt, was the major contributor to the overall supply growth.

Lignite production in OECD non-member economies increased 4% (+10.4 Mt). India accounted for the largest decrease, with a 11% drop (-5 Mt), whereas 15% (+4.6 Mt) increased production in Bulgaria, 6% (+4.3 Mt) in Russia and 26% (+7.6 Mt) in Serbia more than offset the difference.

Table 1.7 Hard coal and lignite production among selected OECD non-member economies (Mt)

Country	Hard coal			Lignite		
	2014	2015*	Difference	2014	2015*	Difference
Bulgaria	-	-	-	31.3	35.9	15%
China[14]	3 640.2	3 527.2	-	-	-	-
Colombia	88.6	90.3	2%	-	-	-
India	609.2	648.1	6%	48.3	43.2	-11%
Indonesia**	484.7	469.3	-3%	-	-	-
Kazakhstan	107.1	101.0	-6%	6.9	6.2	-10%
Romania	0.1	-	-100%	23.5	25.5	9%
Russia	264.0	276.0	5%	68.9	73.2	6%
Serbia	-	-	-	30.0	37.7	26%
South Africa	260.5	252.1	-3%	-	-	-
Ukraine	55.3	32.6	-41%	0.1	-	-100%
Viet Nam	41.7	37.2	-11%	-	-	-

* Estimate.
** Lignite makes up a portion of coal production in Indonesia.
Source: IEA (2016a), *Coal Information 2016*, www.iea.org/statistics/.

[14] China produces lignite, but it is not reported as such

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2. RECENT TRENDS IN INTERNATIONAL COAL TRADING

Key findings

- **Total seaborne coal trade declined for the first time since the financial crisis of 2008.** Both thermal coal and metallurgical (met) coal seaborne trade declined. Traded coal volume decreased 5.4% from 1 224 million tonnes (Mt) in 2014 to 1 158 Mt in 2015. Seaborne trade accounted for 88% of total international coal trade.

- **India became the largest coal importer in the world, followed closely by the People's Republic of China (hereafter "China") and then Japan.** Despite the 6.7% decrease in Indian imports, India overtook China owing to the almost 30% decline in Chinese imports.

- **Viet Nam has become a net coal importer.** Exports in Viet Nam dropped from 10 Mt in 2014 to around 2 Mt in 2015, while at the same time imports increased from 3 Mt to 6 Mt. Viet Nam has thus become a net importer of coal as expected.

- **Coal imports to Germany, the largest coal importer in Europe, increased in 2015,** despite a slight decline in coal-generated electricity in 2015, compared to 2014. Declining domestic production played a major role.

- **Australia remains the largest coal exporter, providing more than half of global met coal exports.** Amid a 3.7% decrease in global met coal exports, Australian met coal exports rose by 4%. Thus, the share of Australia in total met coal exports in the world has increased to 63%.

- **Coal prices have risen unexpectedly, mainly driven by supply-side policy changes in China.** As of October 2016, spot thermal coal prices have doubled since January, and spot met coal prices have quadrupled.

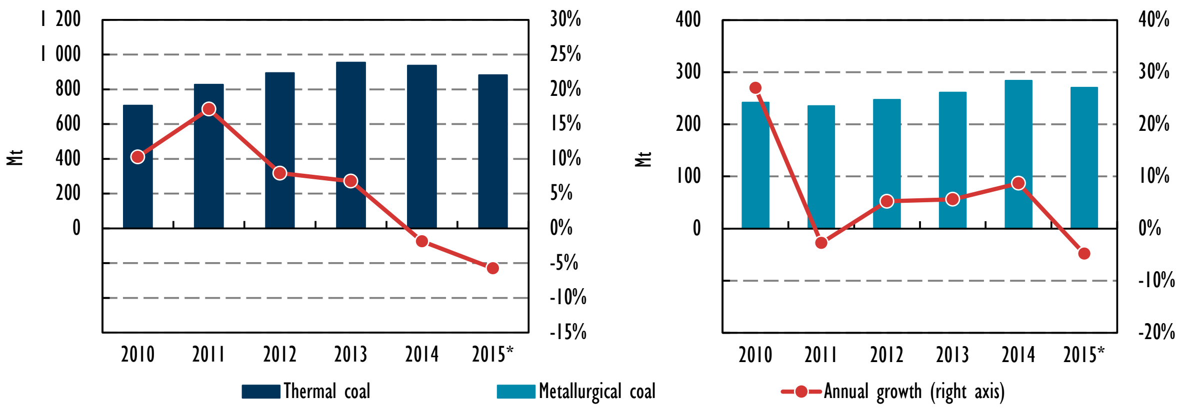
- **Mining costs fell in every major exporting country in the world.** Further productivity improvements were carried out by mining companies to reduce operating costs. Australian exporters in particular were successful at cost cutting; by 2015, some companies had cut their costs in half compared to 2010 levels.

The international coal market

After more than 20 years of continuous growth, international coal trade, including seaborne and inland trade, decreased for the first time in 2015. The total traded volume amounted to 1 311 Mt, 4.1% (-56 Mt) lower than in 2014. Thermal coal accounted for 76% (1 003 Mt) of the total traded volume, whereas the share of met coal was 23% (299 Mt); a small amount of lignite trade made up the remainder. Steam coal trade was 4.3% (-45 Mt) lower than in 2014, and the amount of met coal traded also decreased 3.7% (-11.5 Mt) in 2015.

Seaborne trade accounted for 88% of total international coal trade in 2015. In parallel with the decrease in total coal trade, seaborne trade was 5.4% (-74 Mt) lower in 2015. The total seaborne traded volume of 1 158 Mt consisted of 883 Mt of steam coal and 270 Mt of met coal. Seaborne trade volumes of steam coal were 5.8% lower than in 2014, and met coal was 5% lower.

Figure 2.1 Market development of seaborne thermal (left) and met coal (right), 2010-15

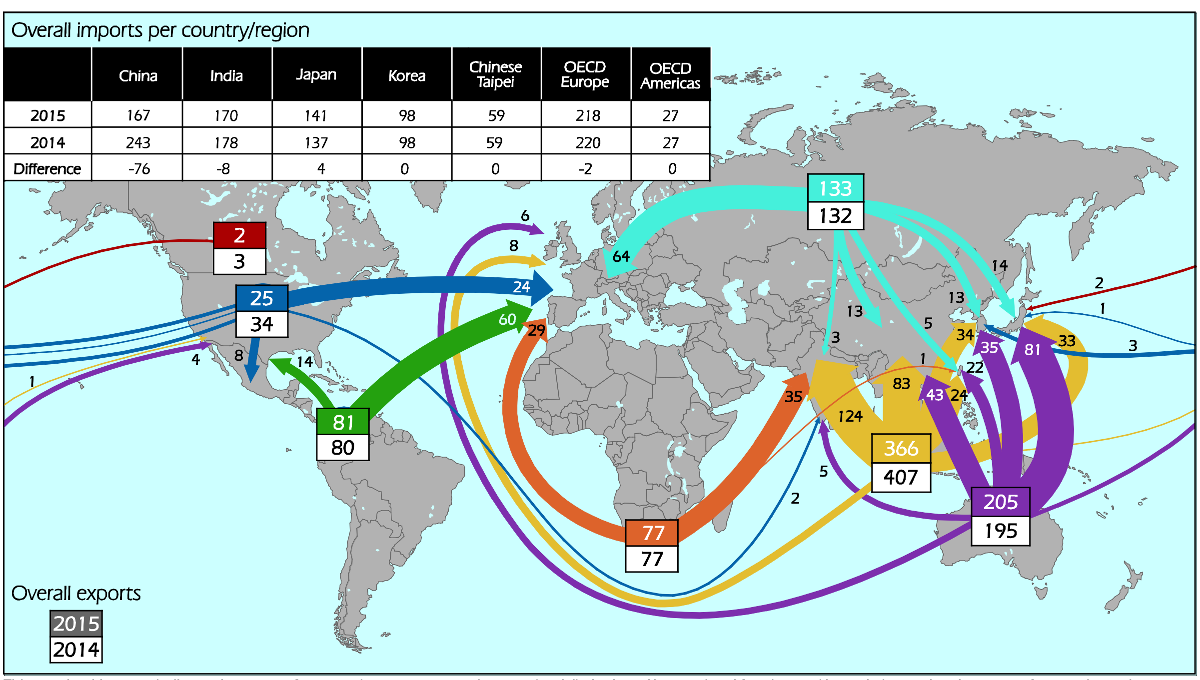


* Estimate.

International thermal coal trade

Thermal coal trade has grown significantly in recent years. Still, the majority of domestic coal production is also consumed domestically: only 17% is traded internationally, and about 90% of this trade is seaborne.

Map 2.1 Trade flows in the seaborne thermal coal market, 2015



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

Note: Exports from Russia to Europe include exports via railway.

Map 2.1 illustrates the major trade flows for thermal coal trade. It can be seen that the Pacific Basin hosts the largest exporters and importers, and is therefore of particular importance in the global thermal coal trade. Indonesia continued to be the largest exporter of thermal coal in 2015, followed by Australia and Russia. Among importer countries, India surpassed China in 2015 to become the largest thermal coal importer. China and Japan were the second- and the third-largest importers of thermal coal, respectively.

In 2015, the ongoing trend of exports shifting from their traditional destinations towards India and other developing Asian countries became more apparent. This pattern can be clearly seen in Table 2.1, which presents thermal coal trade flows between individual countries in 2015; net changes from 2014 are also included with colour-coded shading. As can be observed, steam coal exports to China decreased substantially in 2015, and volumes shifted to India and other Asian destinations. In the case of Indonesia, exports to China – and to some extent to India – declined particularly sharply. Quality regulations in China that came into effect in 2015 seem to have had an especially harsh impact on Indonesian exports; likewise, Indonesian exports to India were also hit hard, having been outcompeted by higher-calorific value (CV) South African exports. The only markets in which Indonesia was able to increase exports were in other developing countries in Southeast Asia; despite this, Indonesian exports decreased significantly overall. Australian total steam coal exports, on the other hand, grew considerably. Despite its declining exports to China, Australia was able to increase exports to India, Chinese Taipei, Korea and other Asian countries. South African exports to India and other Asian countries similarly increased, while exports from South Africa to Europe dropped.

Table 2.1 Thermal coal exports in 2015 (Mt) and net changes from 2014 (colour-coded), in Mt[15]

From \ To	China	India	Japan	Korea	Chinese Taipei	Europe	Other Asia	TOTAL
Indonesia	83	125	33	34	24	9	57	365
Australia	43	8	81	35	22	-	11	201
Colombia	-	-	-	-	-	59	-	59
United States	-	2	1	3	-	13	-	19
South Africa	-	35	-	-	1	16	7	59
Russia	13	3	14	13	5	68	5	121
TOTAL	139	173	128	85	53	164	80	-

-45 Mt 0 +15 Mt

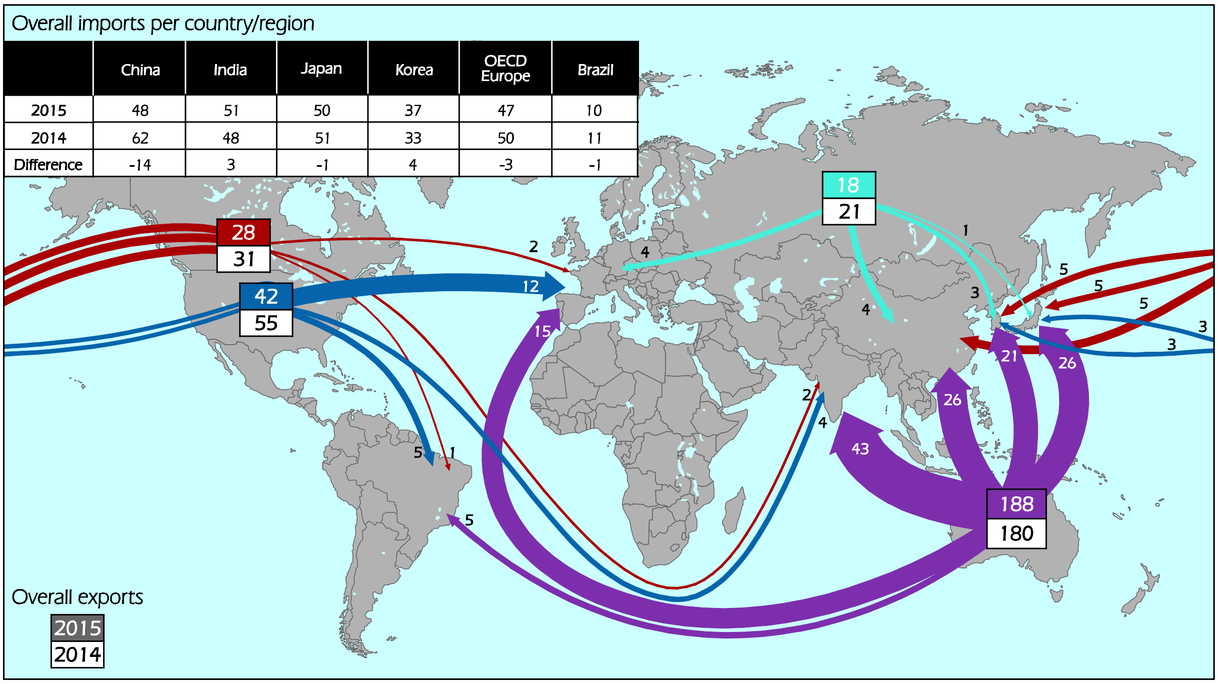
International met coal trade

The international trade of met coal accounted for almost 30% of global met coal consumption in 2015. With a share of 88%, seaborne trade plays a major role in global met coal trade. As can be seen in Map 2.2, which illustrates major met coal trade flows for 2015, the international met coal market is highly concentrated in terms of supply. Only three countries are responsible for more

[15] TOTAL in this Table refers only to the trade between the countries/regions included in the Table

than 80% of global met coal exports. The largest exporter of met coal is Australia (63%), followed by the United States (14%) and Canada (9%). As for importing countries, India, Japan and China import the most. As an aggregation of countries, OECD Europe is also a significant importer.

Map 2.2 Seaborne trade flows in the met coal market, 2015



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Note: Exports from Russia to Europe include exports via railway

Regional analysis

Exporters

Australia

Total Australian coal exports increased by 4.6% (+17 Mt) in 2015 to a volume of 392 Mt. In addition to already being the largest exporter in terms of energy content, Australia surpassed Indonesia in tonnage in 2015 to become the largest exporter overall, with a 30% share in the global coal trade. The growth in exports was due to a combination of an increase in steam coal exports by 5.2% (+10 Mt) and a 4% (+7.2 Mt) growth in met coal exports. Australia continued to be the largest met coal exporter in 2015 with a total export volume of 188 Mt, coming mainly from mines in Queensland.

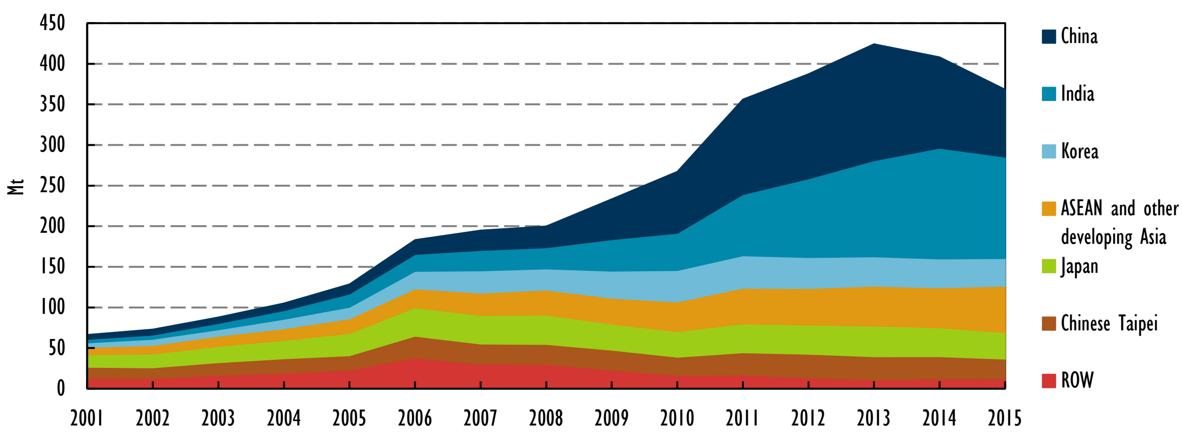
The largest share of Australian coal exports in 2015 (33%) were sent to Japan. China followed as the second destination, receiving 18% of total exports; Korea received 15%; and India received 12%. Total coal exports to Japan and Korea increased in 2015 by 10% (+12 Mt) and 13% (+7 Mt), respectively. Exports to China, on the other hand, decreased by 21% (-19 Mt), while exports to India increased by about 7% (+3 Mt). Total revenue from Australian coal exports in the 2014/15 fiscal year was USD 28 billion, which was 20% lower than in 2014. Despite increased exports in 2015, revenue from coal exports decreased owing to lower market prices. About 58% of the revenue came from met coal exports.

Indonesia

Indonesian total coal exports declined in 2015 for the second year in a row, decreasing by 9.8% (-40 Mt) to 368 Mt. Once the largest coal exporter in the world, Indonesia has fallen behind Australia in terms of both tonnage and energy content of total exports. Moreover, the percentage of total production exported fell from 84% in 2014 to 79% in 2015. The share of Indonesian exports in the global coal trade similarly fell, from 30% to 28%. Note that a large share of the steam coal exported from Indonesia is high-moisture, low-calorific coal.[16] Indonesia continued to be the largest exporter of steam coal in 2015.

Over the past decade, increased demand in China for imports was the main factor driving growth in Indonesian coal exports. In 2015, however, coal exports to China from Indonesia decreased by 26%. Recent low prices and decreasing Chinese demand have, therefore, particularly affected Indonesian exports. Indonesian exports to India have dropped as well (8% from 2014) because growth in Indian demand was largely for high-energy coal. On the other hand, exports to Japan and Korea remained basically unchanged, and exports to the Association of Southeast Asian Nations (ASEAN) and other developing Asian countries increased by 16%.

Figure 2.2 Indonesian export destinations, 2001-15



Note: ROW = rest of world.

Various other factors have also contributed to the decline in Indonesian exports. The new regulation necessitating letters of credit for exports to reduce illegal mining has caused hardships for small, legitimate producers who lack the business structure to meet the requirements. Moreover, making use of the rupiah mandatory for conducting business instead of the US dollar has increased uncertainty for producers given that the rupiah is a volatile currency.

A new 1.5% prepaid income tax on coal sales by Izin Usaha Pertambangan (IUP) (mining business license) holders – to be paid before the shipment clears customs – as well as increased forestry access charges have further increased costs for Indonesian producers and caused exports to decrease. In addition, forest fires in Sumatra forced producers to halt mining, droughts disrupted the barging of export coal in rivers in South Kalimantan, and piracy incidents disrupted shipments from Kalimantan.

[16] Some lignite, although not reported as such, is included.

Russia

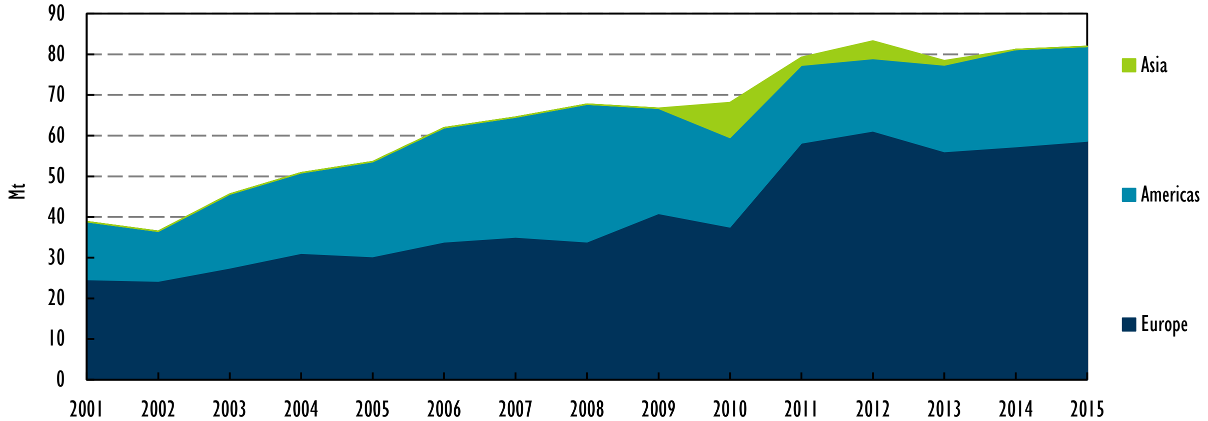
Russia continued to be the third-largest coal exporter in the world. Russian coal exports remained roughly unchanged at 155 Mt in 2015. Steam coal exports increased by 1% (+1.4 Mt) to 133.4 Mt in 2015 and accounted for 86% of the exports. Met coal exports decreased by 13% to 18 Mt, and small quantities of lignite exports made up the remainder. Although OECD Europe received 6% less Russian coal than in 2014, it still remained the primary destination for Russian exports in 2015, with a total of 68 Mt. For the first time, Russian coal is to be shipped from its eastern Vostochny port to Chile in 2016 – a further indicator of the very low freight rates in the current dry bulk shipping market.

Colombia

Around 90% of total Colombian coal production is exported and consists almost entirely of steam coal. In 2015, Colombian exports increased slightly, by about 1% to 82 Mt. As a result of the significant decrease in US exports, Colombia climbed up from the fifth position to become the fourth-largest coal exporter. The largest export destinations are European countries, followed by the Americas. There were exports to Asia during the period 2009-13, but these stopped in 2014 owing to the disappearance of favourable price spreads. Interestingly, Colombia began exporting to Asian countries again in early 2016: in the first half of 2016 exports to India totalled around 2.6 Mt, and 0.4 Mt of coal was exported to South Korea. For a more detailed analysis of this phenomenon, see the “Prices” section.

In 2015, Colombian exports were affected largely by lower prices and various internal problems. A nine-month ban on night train transport caused the exports of Drummond mining company – one of the three majors in Colombia – to decline significantly. Further, when Venezuela closed the border with Norte de Santander, it complicated logistics and resulted in substantial losses because producers in Norte de Santander used to export their coal through the closer Venezuelan ports.

Figure 2.3 Colombian export destinations, 2001-15



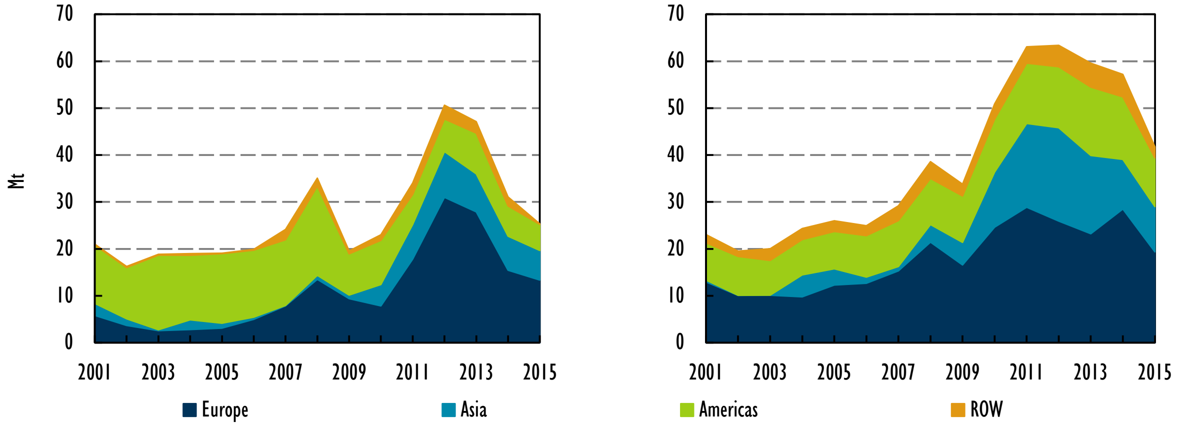
United States

Exports from the United States decreased significantly in 2015 to 67 Mt, indicating a decline of 24% (-21 Mt). Steam coal exports dropped sharply, by 25% (-8.4 Mt), and met coal exports decreased similarly, by 23% (-13 Mt). Total revenue from coal exports in the United States also fell substantially in 2015, dropping 33% to USD 5.7 billion, with met coal accounting for 72% of the total export revenue. The overall decrease in coal exports from the United States was caused by various factors.

US producers have generally higher costs and as a result are affected more adversely by lower coal prices. They are also at a further competitive disadvantage due to the strong US dollar compared with the depreciating currencies of other exporting countries.

Europe continued to be the primary export destination for US coal exports in 2015, even though both steam coal and met coal exports to Europe declined significantly. Met coal exports to Asia also declined, but the overall decrease was less pronounced. In contrast, exports to India increased by almost 40% (+2 Mt) to 6 Mt as a result of growing Indian demand.

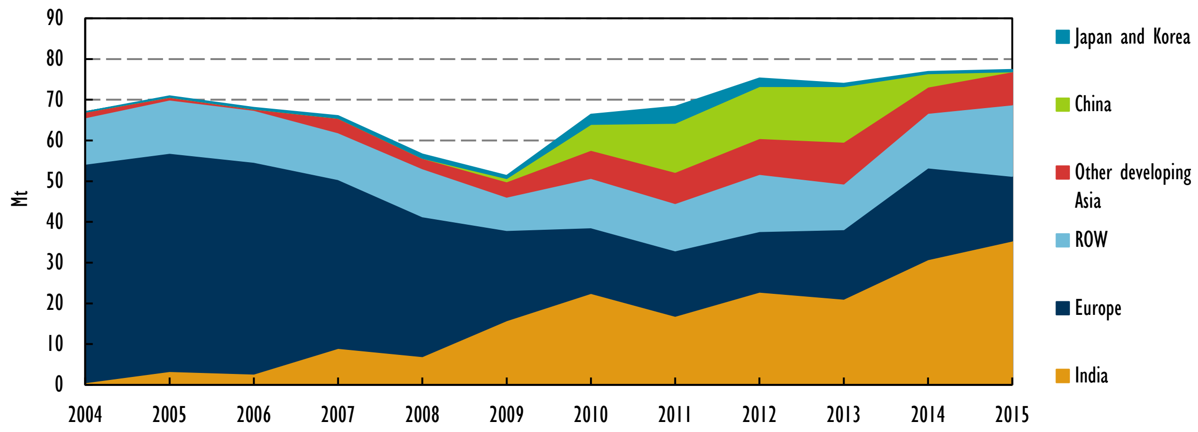
Figure 2.4 US exports of thermal coal (left) and met coal (right), 2001-15



South Africa

Exports from South Africa remained roughly unchanged at 77 Mt in 2015. The exported volume of South African coal consists almost entirely of steam coal. Around 30% of produced coal was exported, while the rest, mainly lower calorific value coal, was utilised in domestic consumption. A coal mining strike lasting nine days in October 2015 disrupted the flow of coal to the seaborne market via Richards Bay port, resulting in a 2 Mt loss of exports.

Figure 2.5 South African export destinations, 2004-15



The decline in South African coal exports to Europe, which began several years ago, continues with the exception of Turkey, which has received significantly greater South African exports in recent years. Exports are moving to India, now the largest destination for South African coal.

Conversely, exports to China, which had been declining since 2013, vanished completely in 2015. Other developing Asian countries received South African exports, such as Sri Lanka (1.2 Mt) and Bangladesh (0.8 Mt), a substantial increase from almost nothing in the past.

Canada

Canadian exports decreased by about 11% (-4 Mt) to 30 Mt in 2015, with met coal making up a very large portion of the overall exports (28 Mt). Despite decreased exports in 2015, Canada remains the third-largest met coal exporter in the world. The major export destinations for Canada are the Asian markets: in 2015, the countries receiving the largest amount of Canadian coal exports were again China (5 Mt), Japan (8 Mt) and South Korea (6 Mt); however, there was a significant decline from 2014. Coal exports to Asia are shipped from the Westshore, Ridley and Neptune Bulk terminals on the Pacific coast. Among European export destinations, a substantially higher amount of coal was exported to Ukraine and Turkey than in 2014.

Poland

Poland exported 9.2 Mt of coal in 2015, of which 2.3 Mt was coking coal and 6.9 Mt was steam coal. While this is a substantial decline from 1990 (30 Mt), Poland remains the largest coal exporter in OECD Europe. The Czech Republic is the main recipient of Polish coking exports (1.3 Mt in 2015). Germany (2.7 Mt in 2015) and the Czech Republic are the main recipients of Polish steam coal, but further destinations, such as Egypt, Morocco and Turkey, also receive some steam coal exports.

Other countries

Coal exports from **Viet Nam** dropped drastically, from 10 Mt in 2014 to around 2 Mt in 2015. The main reason for this export decrease was increased domestic consumption in Viet Nam as a result of newly commissioned coal power plants. Consequently, Viet Nam switched from being a net exporter to a net importer in 2015 – as forecast previously in the *Medium-Term Coal Market Report*. Viet Nam continued ramping up its coal imports in 2016, eventually importing more coal in the first half of 2016 than in the whole of 2015.

Kazakhstan exported 27 Mt of coal in 2015, 11% (-3.5 Mt) less than in 2014. The main export destination for Kazakh coal was Russia, as in previous years. However, depreciation of the Russian ruble in recent years has made Kazakh coal less competitive in Russia, and it is being partially replaced with coal produced domestically. The Kazakh government has therefore been looking for ways to diversify its export destinations, most notably towards India and China. To this end, the Kazakh and Indian governments have established an inter-ministerial work group for the financing of coal mining projects in Kazakhstan. Similarly, various agreements for economic co-operation were signed with China in September 2015, among which the development of a coal processing plant in the region of Karaganda was agreed upon.

Exports from the **Democratic People's Republic of Korea** increased 27% (+4 Mt) in 2015 to 20 Mt, with the vast majority exported to China. Despite decreasing Chinese demand, North Korea was able to increase its market share. Viet Nam had long been a primary supplier of anthracite to China, but the increase in domestic consumption in Viet Nam cut Vietnamese exports dramatically, and North Korea successfully filled the gap. Exports from North Korea to China continued in 2016, despite sanctions against North Korea by the United Nations Security Council in March 2016.

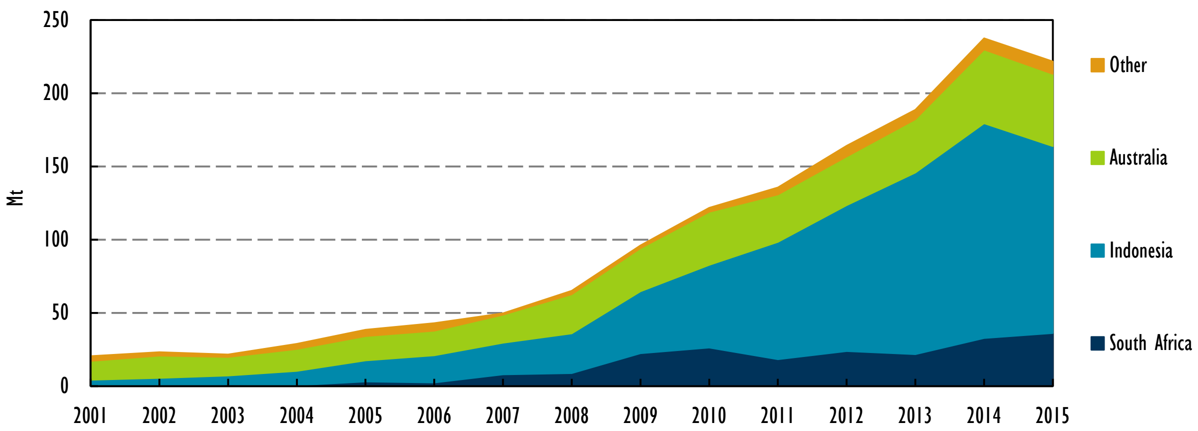
Mozambique exported 4.5 Mt of coal in 2015, about 5% (-0.2 Mt) less than in 2014. Various new export infrastructure projects have become operational in recent years. For example, the port of Nacala and the Nacala rail corridor, which connects Moatize with the Nacala port, began operating in 2015. Nevertheless, in January 2016, Vale wrote off more than USD 2 billion of their 2015 mining assets in Mozambique. One particular issue with Mozambican coal is its high ash content and the presence of certain trace elements that makes the coal usable by a smaller range of customers. Blending it with low-ash coal is necessary for various consumers.

Importers

India

India imported 222 Mt of coal in 2015, 7% (-16 Mt) less than in 2014. Despite the decrease in imports, India overtook China to become the largest coal importer in the world in 2015. Although steam coal imports declined a significant 8% (-15 Mt), they still constituted almost 77% of total imports. Met coal imports also declined but very slightly, by 1% (-0.6 Mt).

Figure 2.6 Yearly Indian coal imports, 2001-15



Imports from Indonesia continued to account for the largest portion of total Indian imports, with a share of 58%. However, Indonesian imports, which decreased for the first time in a decade, were 13% (-19 Mt) lower than in 2014. Imports from Australia also declined, albeit by a very slight 2% (-1 Mt). In contrast, growth in South African imports, which began several years ago, continued with a 10% (+3 Mt) increase from 2014.

In order to reduce the current budget deficit, the Indian government is pursuing a policy to rapidly decrease thermal coal imports in the near future. As part of this policy, production is being expanded in existing mines and transportation improved to ease evacuation bottlenecks; this has prompted a large increase in domestic production which, combined with the slightly lower growth in coal demand, has resulted in a consequent decrease in imports. Various power plants in India have long-term contracts with Indonesia for coal supply, but, due to changes in pricing and regulations in the Indonesian coal market, operation of these plants has become costlier. For this reason, a compensatory tariff was requested by the companies; tariff agreement procedures are still ongoing.

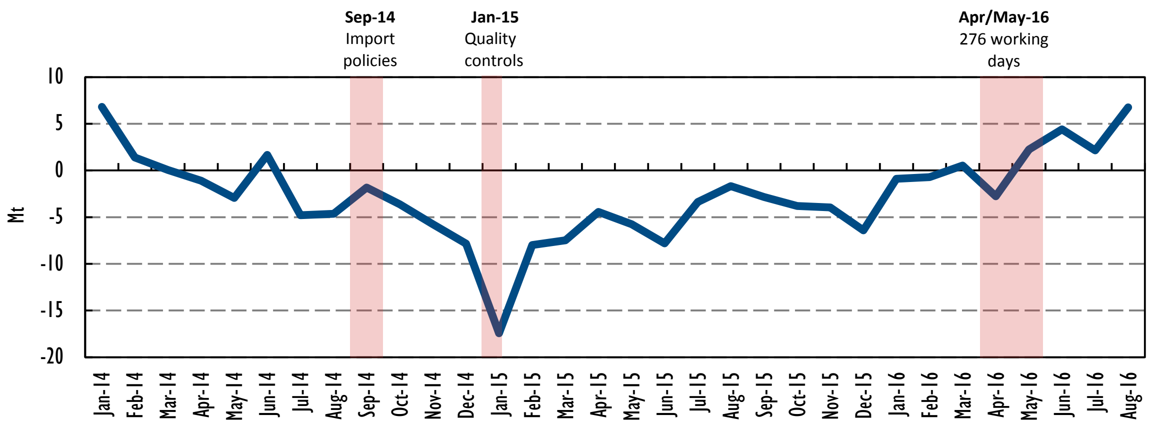
China

Chinese coal imports declined for the second year in a row in 2015, by almost 30% (-90 Mt) to 215 Mt. With this significant decrease, China fell behind India to become the second-largest coal importer in the world. Steam coal imports to China totalled 167 Mt in 2015, about 31% less than in the previous year. Similarly, met coal imports dropped to 48 Mt – a 23% decrease from 2014. In 2015, 78% of the imported coal in China was steam coal.

Imports from Indonesia decreased by 30% (-35 Mt) in 2015. Regardless, Indonesia continued to be China's largest supplier, accounting for 39% of total imports. Australia followed as the second-largest supplier at 33% of total imports, even though imports from Australia similarly decreased in 2015, by 25% (-24 Mt). Australia continued to be the largest supplier of met coal to China in 2015, followed by Mongolia.

The major reason for the decrease in Chinese coal imports in 2015 was declining demand as a result of economic restructuring, combined with oversupply in the domestic market. In addition, domestic coal is becoming more competitive as mining shifts towards lower-cost regions while transportation bottlenecks are resolved. Policies also have a significant impact on imports in China, as shown in Figure 2.7, which illustrates monthly year-on-year change on Chinese coal imports.

Figure 2.7 Monthly year-on-year difference of Chinese coal imports, 2014-16



Import taxes were introduced in October 2014 to control import volumes into China, which had skyrocketed from 2009 when China became a net importer. These taxes, together with directives sent to large consumers to reduce imports around September 2014, were very effective in curbing Chinese imports from 2014. Moreover, domestic coal took precedence over imports as a result of lower prices in the domestic market and depreciation of the Chinese yuan during the fourth quarter of 2015.

Quality regulation, begun in January 2015, also affected coal imports because analysing imported coal in the ports delays shipments to customers by 10 to 20 days. Third-party tests are not accepted, and shipments that do not satisfy Chinese quality tests are rejected. Given the regulation required high energy content and low ash coal, shipments from Indonesia in particular, as well as anthracite barges from Viet Nam, were mainly affected, resulting in a significant drop in imports from those countries. Various shipments from South Africa and Australia were also rejected. However, policy changes introduced in 2016 to cut the oversupply, such as reducing working days for miners from

330 to 276 per year (instituted in April and May 2016 onwards – the start date varied among different provinces) reversed the downward trajectory, underpinned by strong demand driven by a summer heatwave. As a result, Chinese imports surged again from that point. For a more detailed analysis of this phenomenon see the “Prices” section.

Japan

Japan has negligible domestic production and therefore needs to import almost all of its coal. In 2015, Japan imported 192 Mt of coal, or 2% more than in 2014; it remained the third-largest coal importer in the world. Imports of steam coal increased by 3% (+4 Mt) from 2014, whereas met coal imports decreased by 1.5% (-0.8 Mt).

Imports from Australia account for 65% of total Japanese coal imports, making Australia the largest coal supplier to Japan, followed by Indonesia, with a share of 17%, and Russia, with 9%. Imports from Australia increased by about 5% (+6 Mt) and from Russia by 12% (+2 Mt) in 2015, but imports from Indonesia were 8% (-3 Mt) lower. Australian coal is preferred by Japanese power plants for its high calorific value compared with Indonesian coal; the price stability offered by long-term contracts and the consistent quality of Australian coal also contribute to this preference.

Korea

Korea is strongly dependent on imports to satisfy its coal demand due to lack of coal reserves. The world’s fourth-largest importer, Korea imported 135 Mt of coal in 2015. The 3% (+4 Mt) overall growth from 2014 was due mainly to a 12% (+4 Mt) increase in met coal imports. Imports from Australia accounted for 45% of total coal imports, followed by Indonesia with a share of 25% and Russia with 17%.

OECD Europe

OECD Europe coal imports decreased by 1.8% (-4.8 Mt) in 2015 for a total 267 Mt. Imports of steam coal decreased by a slight 0.7% (-1.6 Mt), whereas met coal imports had a stronger decline of 5.7% (-2.8 Mt). A small amount of lignite continued to be imported, accounting for the remainder.

Germany remained the largest coal importer in OECD Europe in 2015. With a 3.2% (+1.7 Mt) increase from 2014, German coal imports amounted to 55.5 Mt; growth of steam coal imports by 1.6% (+0.7 Mt) and met coal by 11% (+1 Mt) accounted for the overall increase. Russia was the largest supplier in 2015, providing 16 Mt (30% more than in 2014). The second-largest supplier was the United States at 11 Mt. Colombia followed at 10 Mt, a 40% increase from 2014. This import growth occurred despite the decline in hard coal power generation. However, lower electricity generation from Alpine hydro power plants increased electricity exports to Austria while reduced output from nuclear power plants in France due to warm weather and cooling issues increased exports to France. These factors and the closure of the Grafenrheinfeld nuclear power plant made German coal-fired plants to operate for more hours than expected. This was also supported by clean dark spread remaining preferable to clean spark spread, despite increased transport costs for coal, due to lower water levels in the Rhine and its subsidiaries where many coal power plants are located. As a result, German demand for thermal coal remained strong in 2015, and imports increased amidst decreasing domestic production.

Turkey became the second-largest coal importer in OECD Europe in 2015 with 34 Mt of total imports, indicating 14% (+4 Mt) growth over 2014. The increase in total imports stemmed almost entirely from steam coal imports, which resulted from a surge in steam coal consumption in the Turkish power sector after a substantial decrease in lignite mining. Russia and Colombia, both providing 11 Mt, continued to be the largest suppliers to Turkey in 2015. Imports from the United States decreased considerably (-2.4 Mt) to 2 Mt, and imports from Australia conversely increased substantially (+2 Mt) to 2.6 Mt. In 2014 Ukraine supplied Turkey with about 1 Mt of coal, but in 2015 imports from Ukraine were almost non-existent as a result of supply disruptions due to the conflict in the country.

Coal imports to the **United Kingdom** decreased drastically in 2015 as a result of a significant decline in demand on the back of the rising cost of generation due to the carbon tax: UK coal imports totalled 25 Mt in 2015, indicating a 39% drop from 2014. The largest supplier to the United Kingdom in 2015 was Russia (9 Mt). Colombia (7 Mt) surpassed the United States (5 Mt) to become the second-largest supplier.

Italian coal imports declined slightly, by 1.5% (-0.3 Mt), to 19.6 Mt in 2015. In contrast, coal imports by **Spain** grew significantly, by 16% (+2.6 Mt) to a total of 19 Mt. This increase was due entirely to growth in steam coal imports mainly driven by lower hydropower generation and also by the fall in domestic coal production.

Poland imported 8.5 Mt of hard coal in 2015, of which 2.7 Mt was coking coal and the balance was thermal coal. Because of the quality and price of its coal, the main exporter to Poland is Russia, accounting for 60% of Polish coal imports, of which 4.8 Mt are thermal coal. This represents almost 90% of the Polish thermal coal imports. The main provider of coking coal is Australia (1.5 Mt in 2015), followed by the Czech Republic (0.5 Mt in 2015). The reasons for Czech Republic imports and exports happening at the same time are related to quality, seasonality and geography. Coal traded between Czech Republic and Poland is produced near the border of the two countries.

Other countries

Chinese Taipei continued to be the world's fifth-largest coal importer as imports in 2015 remained roughly unchanged. Of the 66 Mt of total coal imported, 59 Mt were steam coal imports, accounting for 90% of total imports. Australia was the largest supplier to Chinese Taipei (31 Mt), followed by Indonesia (25 Mt). In 2015, 7 Mt of coal was imported from Russia, which is a remarkable 40% increase over 2014.

Russian imports declined slightly by 2% (-0.5 Mt) in 2015 to 26 Mt in total. Imported coal is transported overland from Kazakhstan to be consumed in the power plants near the border, which were built during the Soviet Union era.

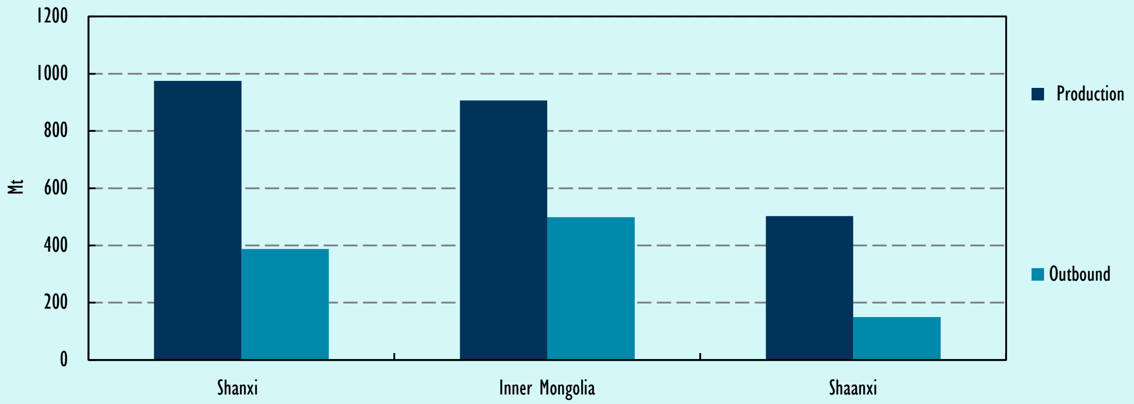
Malaysian coal imports increased by 12% (+2.7 Mt), to 24.4 Mt. The Manjung Unit 4 (1 gigawatt [GW]) ultra-supercritical coal power plant started operation in 2015, followed by the commissioning of another ultra-supercritical plant, Tanjung Bin (1 GW) in March 2016. **Thailand** similarly imported 8% (+1.8 Mt) more coal in 2015, totalling 23 Mt. The imported coal for both countries consists almost entirely of steam coal, with Indonesia and Australia being the largest suppliers.

Total coal imports of **Brazil** remained relatively unchanged in 2015 at 20 Mt. However, steam coal imports increased by 6% (+0.6 Mt), whereas imports of met coal fell 6% (-0.7 Mt). Met coal imports accounted for half of Brazil's total imports.

Box 2.1 Coal trading in China

In China, coal trading is determined by the geographical distribution of domestic production and consumption. Whereas most Chinese provinces are endowed with coal reserves, the main areas of production – linked to large reserves and affordable production costs – are the Northwest and middle provinces, i.e. Shanxi, Inner Mongolia and Shaanxi. In 2015, raw coal production in these three provinces was 2.4 billion tonnes (Bt), two-thirds of total production in China, or three times production in the United States. Consumption in these provinces is less than production, so outbound coal is more than 1 Bt (Figure 2.8). The main consumption centres, however, are in the southeast provinces, especially in the coastal area: Guandong, Zheijang and Jiangsu. Coal is usually transported more than 1 000 kilometres (km) by railway, highway, ports and seaborne ships. The transportation system plays an important role in the coal trade.

Figure 2.8 Coal production and outbound coal of China's main producing regions



In mid-2014, the National Development and Reform Commission (NDRC) published "Guidelines about Stepping up Coal Trading Market System Building" to prompt construction of the national coal trading system. Based on the main producing areas, consuming areas, railway hubs and leading ports, two or three national trading centres are planned which will have annual transactions of more than 200 Mt, and which will provide national coal trading and supply chain services as well as financial services, such as settlement, credit guarantee, etc. The other trading centres at the regional/provincial level are also part of this proposed system. At present, there are about 30 trading centres around the country. Several of them have been important trading facilities for both coal producers and consumers: the China-Taiyuan Coal Transaction Centre; the Inner Mongolia Coal Exchange Centre and Shaanxi Coal Exchange Centre serving main producing areas; the Qinhuangdao Seaborne Coal Market serving leading Bohai rim ports; and the South China Coal Trading Centre serving main consuming areas.

China's National Coal Association and the China Coal Transport and Distribution Association make significant efforts to advance trading system building and rule-making. Every year, they organise the annual coal trade fair and summer coal trade fair, in which mid- to long-term agreements are negotiated between the main producers and consumers. At the coal trade fair in 2015, they published the model text of a coal trading contract, with specific requirements for coal quantity, quality and after-sale issues, etc., to provide guidelines for coal trading.

Box 2.1 Coal trading in China (continued)

In addition to physical trading centres, e-commerce is gaining attention, with more than 80 online trading platforms built in 2015. They are operated by traditional trading centres, third-party electricity companies and large coal companies such as Shenhua and China Coal. In 2015, online platforms run by large coal companies traded more than 200 Mt online; in addition, more than 50 Mt was traded by the top online third-party platform. These online platforms provide information services, electronic payments, electronic bills and online trading integrated with the supply chain. They help to expand market channels, cut market intermediaries, reduce trading costs and improve trading efficiency. However, online coal platforms still face challenges, such as product quality standards, payment systems and competitive value-added services.

With frequent price fluctuations, there has been a trend towards shorter-term, even spot-basis sales. From a socio-economic perspective, however, long-term supply is considered in China to provide more efficient and stable operation of power and steel companies. At the end of 2014, the NDRC encouraged companies to sign mid- to long-term agreements (i.e. no less than one year) which would assure high priority in railway and seaborne transportation. Mid- to long-term agreements are normally settled between large coal companies and power or steel companies – even though, most of the time, contract volumes are agreed when the deal is done, and prices are determined monthly or even weekly, normally below the spot price and mainly based on market demand, coal storage and the main coal price indices. For shorter-term and spot-basis sales, the coal is sold at the prevailing spot price for the day on which the deal is done, or even at the prevailing spot price for the day the coal arrives at its destination.

Among coal price indices, the main price references are the Bohai Rim Steam Coal Price Index (BSPI), which is published weekly by Qinhuangdao Seaborne Coal Market and reflects steam coal prices at major loading ports, and the regional China Coal Price Index (CCPI), which is published weekly by the China National Coal Association and the China Coal Transport and Distribution Association. Other common indices are the China-Taiyuan Coal Transaction Price Index (TCPI), produced weekly by the China-Taiyuan Coal Transaction Centre for steam coal, coking coal and pulverised coal injection (PCI) coal in Shanxi; the Ordos Steam Coal Price Index (OSPI), published weekly by the Inner Mongolia Coal Exchange Centre for steam coal in Inner Mongolia; the Shaanxi Coal Price Index (SCPI), published weekly by Shaanxi Coal Exchange Centre for coal in Shaanxi; and the China Steam Coal Price Index (CSPI), published monthly by the Price Monitoring Centre of the NDRC for national steam coal. Furthermore, coal storage-related data of leading ports of large power or steel companies are also available.

Quality is a fundamental factor in coal pricing. For steam coal, heating value is normally the main factor while ash and sulphur contents are also priced. For coking coal, the main factors are volatile matter, caking index, and ash and sulphur contents. Based on coal price indices, coal with higher ash content, higher sulphur, lower heating value or a lower caking index will be priced at a discount. Remarkably, in China the main price indices of steam coal are usually for 5 500 kilocalorie per kilogramme (kcal/kg) coal. Steam coal with a lower heating value is discounted in proportion to its real heating value. The other factors (sulphur, ash, etc.) – especially if they are combined – need to be negotiated case by case. In January 2015, the national coal quality standard was implemented with the goal of supplying much cleaner coal. This standard set limits on the content of ash, sulphur, phosphorus, fluorine, chlorine, arsenic and mercury; and, for coal being moved more than 600 km, set more stringent limits on heating value as well as ash and sulphur content. High-ash and high-sulphur coal that exceeds the limits is restricted in the Beijing-Tianjin-Hebei area, the Yangtze River Delta and the Pearl River Delta. This new standard affects sales of low-calorific and low-quality coal, such as the lignite in Eastern Inner Mongolia and imported low-calorific Indonesian coal.

Box 2.1 Coal trading in China (continued)

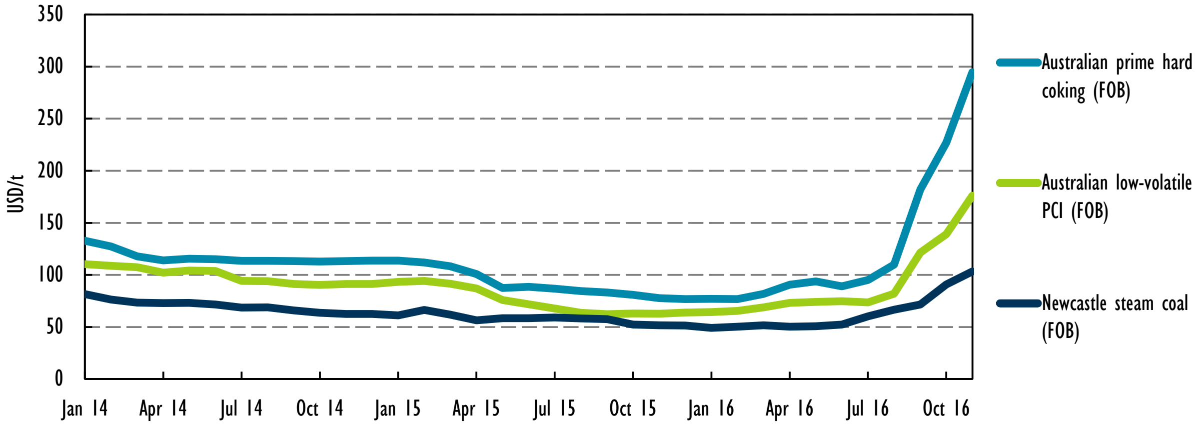
Transportation is an important component of the free-on-board (FOB) price in the leading ports, especially with the main coal-producing areas shifting westwards. With the 2015 downturn in the coal market, not only did the coal price decline, but coal transportation decreased. For example, from 2014, there was an 11.82% decrease (397 Mt) of coal transportation on the Daqin railway. In response, some transportation charges (such as the port surcharge) have been reduced to boost coal trading and transportation. On 4 February 2016, the railway freight charge of coal was cut by CNY 0.01 (USD cents 0.15) per tonne kilometre (tkm), reducing the coal railway freight cost from Inner Mongolia to the Bohai Rim ports by CNY 6 to CNY 12 (USD 0.9 to USD 1.8) per tonne (t). Furthermore, increased railway capacity from the pilot operation of the Mengji railway (from Ordos to Caofeidian Port) at the end of 2015 has created a more competitive transportation market.

2013 was a milestone year in coal derivative development in China. In March 2013, Dalian Commodity Exchange launched coking coal futures; and, in September 2013, Zhengzhou Commodity Exchange launched steam coal futures. In 2014, the large miners began turning to this market in order to hedge the risk of frequent coal price fluctuations. In 2015 the volume of steam coal futures was 432 Mt at CNY 164.82 billion, and the volume of coking coal futures was 960 Mt at CNY 590 billion. Apparently, trading is more active in the coking coal futures market than in the steam coal futures market. To improve underlying coal quality, the new steam coal futures contracts need to meet the new requirement (since January 2016) of 5 500 kcal/kg of material with a sulphur content of less than 0.6% (it was 1% before), volatile matter between 30% and 42%, and an ash content of less than 30%. Moreover, the price discovery role of coal futures has also been gradually recognised by the market. The trend of coal future prices has been consistent with the main price indices; however, the development of coal derivatives in China is slow compared with the large amount of coal production and consumption. The increasing number of price indices available for different regions and coal types also provides more tools for the development of derivative markets, and futures prices should exert increasing influence on the Chinese coal trading system as trade volumes grow.

Prices

Coal is traded in different types and classifications due to it being a heterogeneous product. Variations in coal prices therefore occur not only regionally but also according to coal quality. In Figure 2.9, marker prices for three different coal types exported from Australia are given: prime hard coking coal, low-volatile pulverized coal injection (PCI) coal, and steam coal. All price markers declined during the period 2014-15 due to production cost reductions and the market having been oversupplied. The price declines in prime hard coking and in low-volatile PCI coal were more pronounced than the decline in steam coal price. However, with production cuts in China as well as some supply cuts in Australia and Indonesia, prices rose substantially for all coal types, and met coal prices quadrupled.

Figure 2.9 Coal marker prices for different types of coal, 2014-16

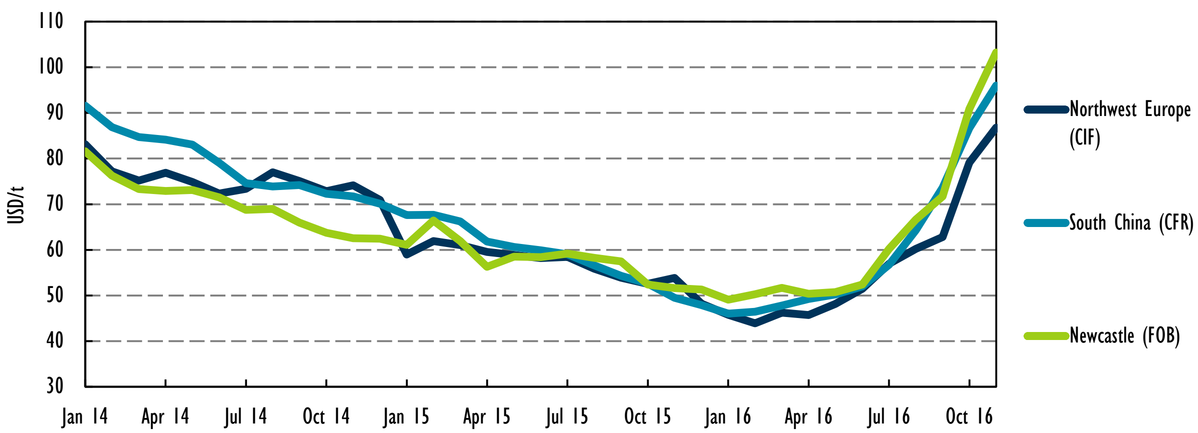


Source: IHS Energy (2016), *Coal McCloskey Price and Statistical Data*, https://connect.ihs.com/industry/coal.

Seaborne thermal coal prices and regional arbitrage

International prices for seaborne traded thermal coal continued to decline in 2015. European thermal coal prices – as indicated by the Amsterdam Rotterdam Antwerp (ARA) cost, insurance and freight (CIF) price index – dropped from USD 59/t in January 2015 to USD 44/t in February 2016, the lowest price since summer 2003. The Chinese and Australian thermal coal price markers also declined significantly. The cost and freight (CFR) index for South China dropped from USD 68/t in January 2015 to USD 46/t in January 2016, and the Australian Newcastle FOB price fell similarly from USD 59/t to USD 49/t during the same period. However, in early 2016 international thermal coal prices began to rise strongly due to decreased global supply, resulting from mine closures, the scaling back of production and the heavy rain affecting operations at producing mines (in particular in Indonesia).

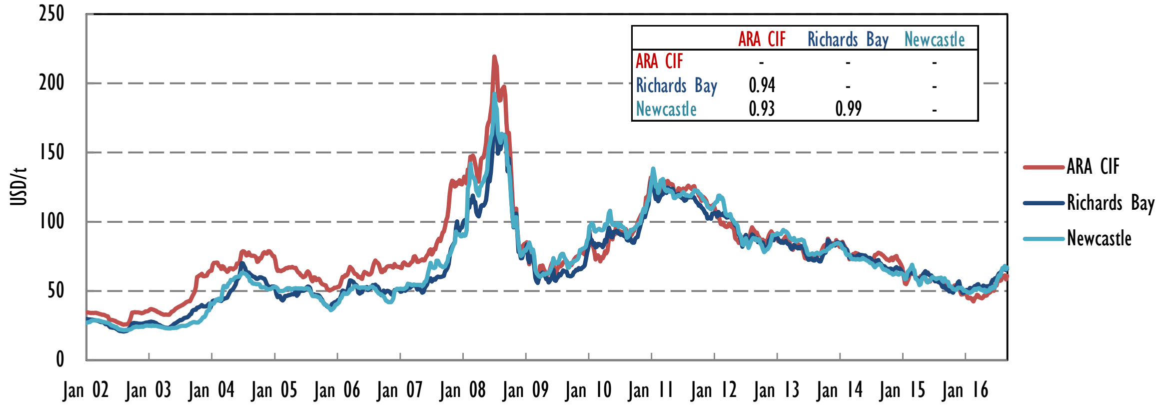
Figure 2.10 Thermal coal price markers in Europe, China and Australia, 2014-16



Source: IHS Energy (2016), *Coal McCloskey Price and Statistical Data*, https://connect.ihs.com/industry/coal.

Traditionally, the international steam coal market was split into two main regions: the Atlantic Basin and the Pacific Basin. In recent years, low freight rates, declining consumption in Europe and increasing demand in Asia has reduced the divide between these two regions. International coal market prices have evolved similarly since differences are quickly balanced by arbitrage, both among international markets and between domestic and international markets in major producers and consumers.

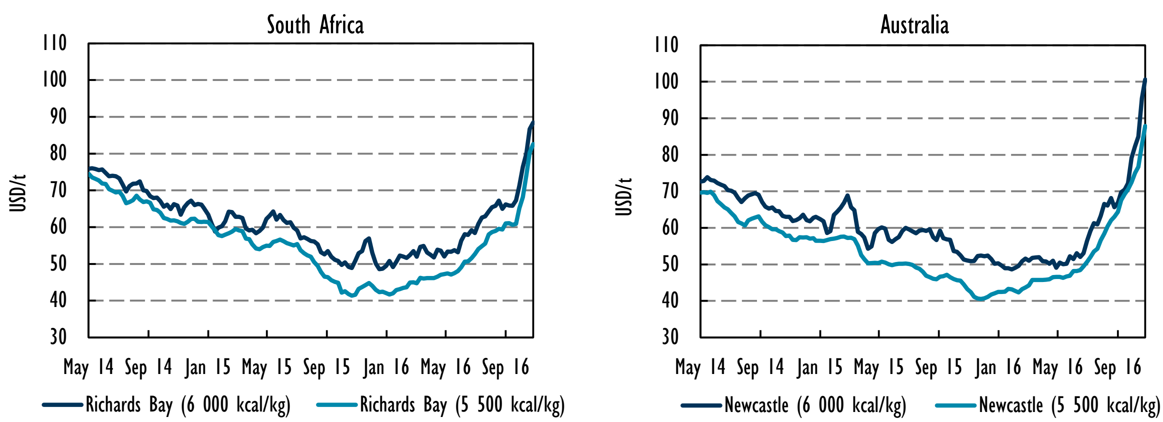
Figure 2.11 Steam coal prices in north-west Europe (ARA CIF), South Africa (Richards Bay) and Australia (Newcastle) and their correlations, 2002-16



Source: IHS Energy (2016), *Coal McCloskey Price and Statistical Data*, https://connect.ihs.com/industry/coal.

Figure 2.11 plots steam coal prices for three different regions – the ARA CIF in north-west Europe, Richards Bay in South Africa and Newcastle in Australia – for the period 2002-16. All three price indexes are well co-integrated, and the correlation coefficient between ARA CIF and Richards Bay is 0.94, while that of ARA CIF and Newcastle is 0.93. The correlation between Newcastle and Richards Bay prices is even higher at 0.99. Prices in international coal markets are thus highly correlated despite regional differences – Newcastle and Richards Bay in particular show close to perfect correlation.

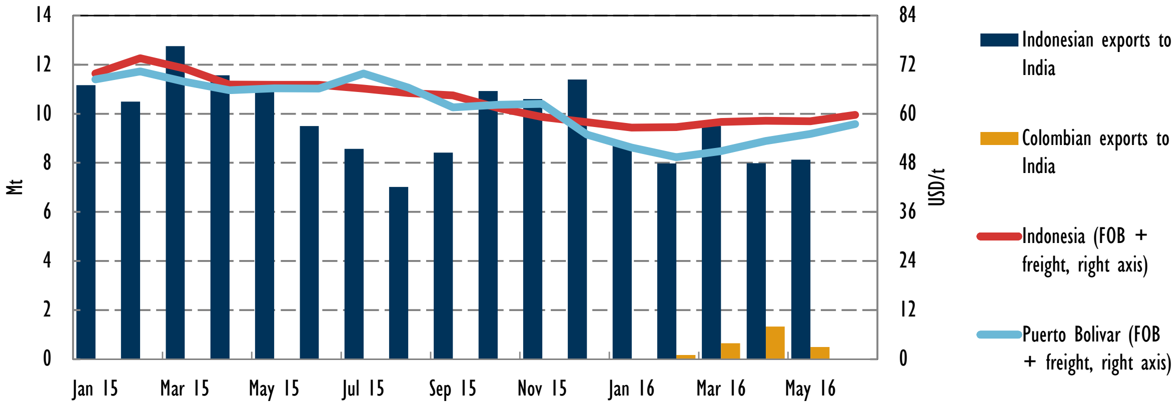
Figure 2.12 Price markers of different thermal coal qualities in South Africa and Australia, standardised to an energy content of 6 000 kcal/kg, 2014-16



Source: IHS Energy (2016), *Coal McCloskey Price and Statistical Data*, https://connect.ihs.com/industry/coal.

In Figure 2.12, price markers for different thermal coal qualities from South Africa and Australia are plotted, with prices standardised to an energy content of 6 000 kcal/kg. Prices for different coal qualities generally increase and decrease at the same time in both South Africa and Australia since opportunities for arbitrage do not last long. It is also clear that the prices for steam coal with higher energy content are almost always higher than for the lower-energy variety, since buyers are willing to pay a premium for the higher energy content.

Figure 2.13 Colombian and Indonesian exports to India and Colombian and Indonesian supply costs in India



An interesting recent phenomenon is that Colombia started exporting to Asia again in the first quarter of 2016. Large volumes to India in particular were exported during this period (2.6 Mt). Colombia exported steam coal to Asia during 2009-13 but stopped in 2014; Figure 2.13 shows monthly Colombian and Indonesian exports to India and demonstrates that supply costs in India are responsible for the halt in Colombian exports. However, falling costs for Colombian producers and very low freight prices resulted in coal shipments from Colombia to cost in India far less than shipments from Indonesia in early 2016. India therefore imported a significant amount of Colombian coal during this period, but rising freight rates in the second quarter of 2016 diminished opportunities for arbitrage and, consequently, no Colombian coal was exported to India in June and July 2016. One major issue with exports from Colombia to Asia is the long shipment time, which can be more than 40 days; this significantly increases the economic risk of shipments during the trip due to changing prices. Another problem is that, while Colombian coal becomes competitive particularly when shipped on large Capesize vessels, only a limited number of ports in India can accommodate Capesize vessels.

Box 2.2 Why did prices increase in 2016?

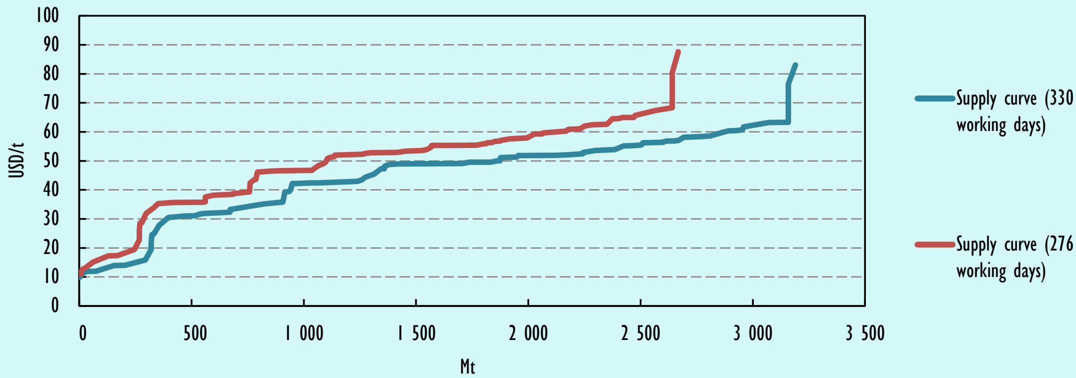
Prices in international coal markets fell in 2015 to their lowest levels since 2003 as the result of a combination of factors, the main one being significant overcapacity on the supply side. The rise in prices in 2016, which accelerated in the third quarter, was therefore an abrupt change in direction. The major contributor to the price hike was tightening global supply since demand did not increase significantly during the period. Policy changes in China played a key role in recent developments: mine closures have been intensive in 2016, adding to over 100 Mt of capacity already closed in 2015, and stocks throughout the supply chain have recently fallen significantly, a detail often overlooked. This has tightened supply; however the main cause of price increases is the reduction of working days for coal miners from 330 to 276. Aiming to tackle the chronic supply glut, the decision did indeed reduce Chinese coal output – but not without various other impacts.

An additional effect of decreased working days in China is an increase in production costs in Chinese coal mines. As the fixed costs remain the same while the output declines, the overall cost of production per tonne actually increases. Figure 2.14 shows this effect in the supply curves of domestic steam coal mines in isolation of other circumstances. In addition to causing the supply curve to shift left due to the production cut, the new regulation also results in the production costs of domestic steam coal to increase by almost 10% on average.

This is putting some high-cost producers out of the money, thus accelerating reductions in production capacity. Although short-term prices depend more on purely variable costs, an average increase in

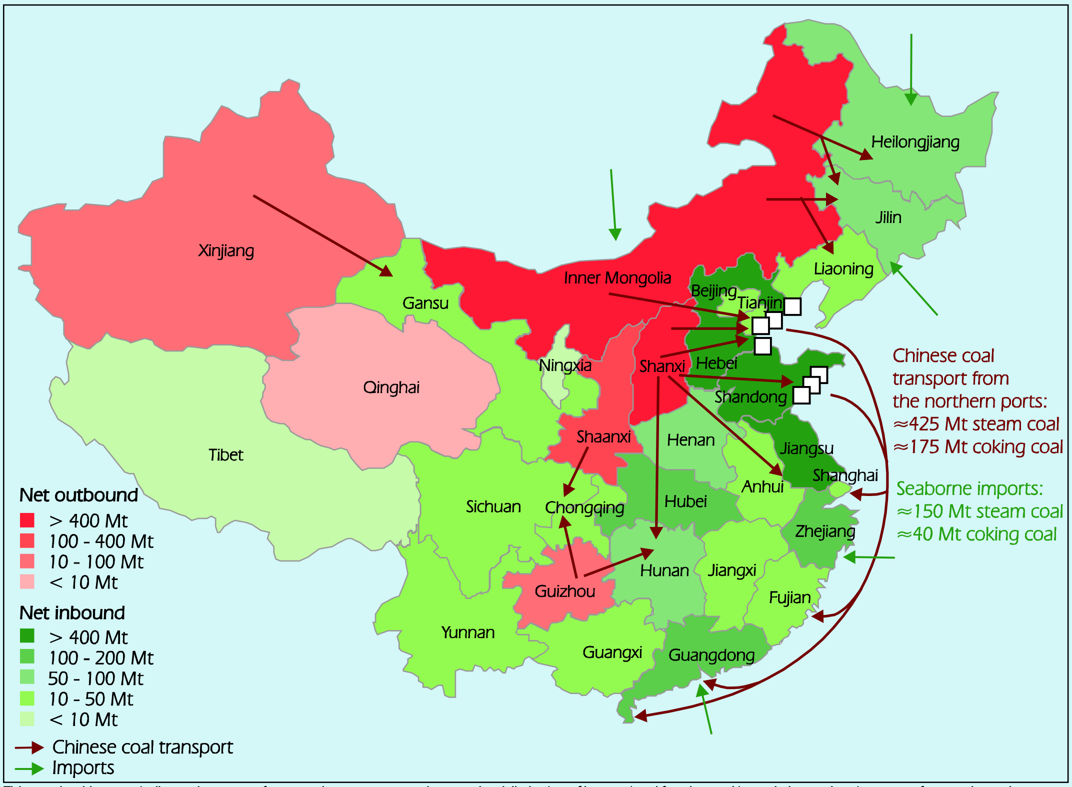
Box 2.2 Why did prices increase in 2016? (continued)

Figure 2.14 Effect of reduced working days on domestic supply costs of steam coal



production costs of almost 10% overnight strongly affects prices in the mid-term. There have also been other factors pushing up prices in 2016: for instance, floods in several southern provinces disturbed transportation of domestic coal to those areas, and a prolonged heatwave provoked stronger power demand in the summer. The final result was a price increase of 30% over the period. Again, the combination of decreased output and increased domestic production prices caused Chinese steam coal imports to surge in this period, reaching a 20-month high in August 2016.

Map 2.3 Chinese coal transport and import flows



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

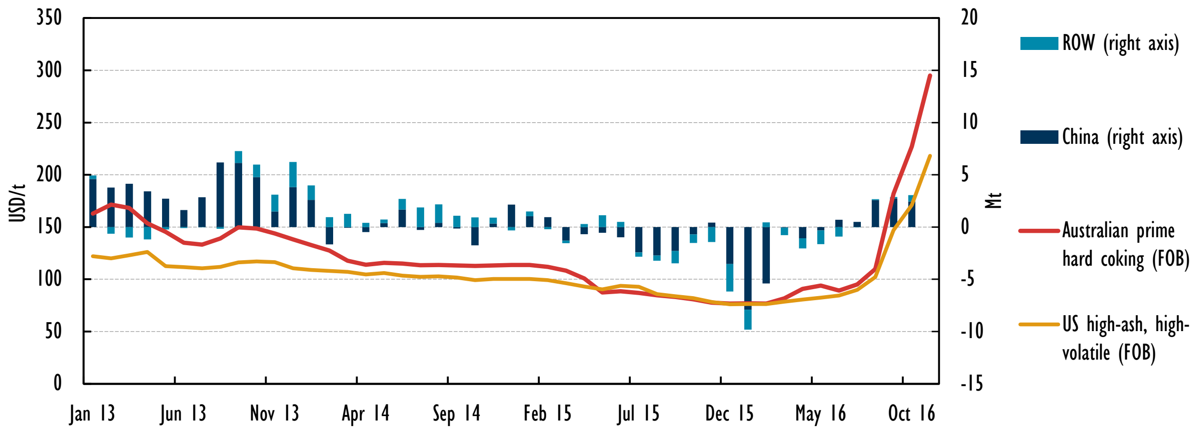
Box 2.2 Why did prices increase in 2016? (continued)

The increase in international coal prices is due, however, to a combination of factors. Apart from structural issues among Indonesian producers as well as the temporary disruptions in Australia and Indonesia resulting from heavy rainfall, it is higher prices and larger imports in China that have especially influenced prices globally. Because the major coal production and demand centres in China are remotely located, a substantial amount of coal is shipped from northern ports (production centres) to southern ports (consumption centres) to meet demand. Approximately 800 Mt of coking coal and steam coal combined arrived at the coastal region in 2015. Of this, around 600 Mt was domestically shipped, and the remainder was imported, mainly from Indonesia and Australia. Chinese domestic and international prices are therefore strongly linked due to the arbitrage effect.

Seaborne met coal prices

The decline in met coal prices continued in 2015. Both Australian prime hard coking and US high-ash, high-volatile coking coal reached their lowest values in December 2015. The price of Australian prime hard coking coal was 32% lower in December 2015 (USD 77/t) than in January 2015 (USD 114/t), and US high-ash, high-volatile coking coal dropped 24%, from USD 100/t to USD 76/t.

Figure 2.15 Met coal prices and monthly year-on-year BFI production, 2013-16



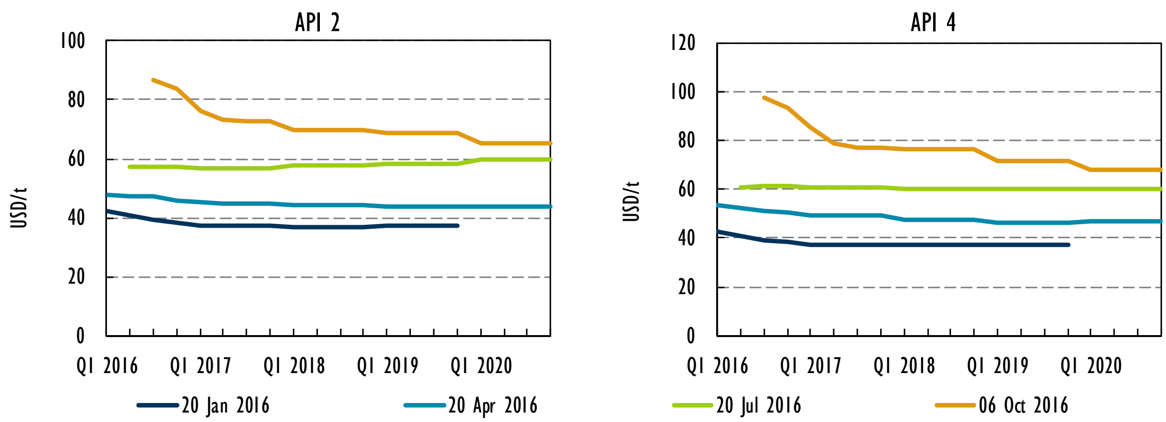
Note: BFI = blast furnace iron.
* BFI production information for November 2016 was not yet available at the time of writing.
Sources: World Steel Association (2013-16), *Iron Production*, www.worldsteel.org/statistics/Iron-production-new.html; IHS Energy (2016), *Coal McCloskey Price and Statistical Data*, https://connect.ihs.com/industry/coal.

One of the main reasons for lower met coal prices in 2015 was the significant drop in global BFI production (contrary to the continuous growth expected a few years ago): China was the main contributor, with a production decline of almost 2%, which exacerbated the global oversupply of met coal. The price premium for Australian prime hard coking over US high-volatile coal largely disappeared during 2015, primarily a result of extensive closures of US high-cost producers, which left the market in short supply of the high-volatile coal that is valued for blending owing to its properties (mainly, fluidity). Nevertheless, met coal prices began rising again in the first half of 2016, with the recent extreme price hike caused largely by supply cuts following the decrease in working days of miners in China. However, it would be too simple to view the new policy on working days as the only factor responsible for the price increase of almost 150% from July to September 2016. Also playing a role in this period were floods in South and East China that disrupted coal transportation, an increase of BFI production in China, and supply disruptions in Australia.

Coal forward prices

As stated in the *Medium-Term Coal Market Report 2015*, backwardation (futures price lower than the spot price) seems to be the new normal in coal markets. After the rise in coal prices in the first half of 2016, in the summer the curve went back to contango (i.e. futures price higher than the spot price), but apparently the market assumes that acceleration in the third quarter is related to Chinese policies that have already relaxed, and to disruptions in some of the major exporting countries. So, the Argus/McCloskey's Coal Price Index 2 (API 2) is in the largest backwardation of recent years. There is not a very large difference between the profiles of API 2 and API 4, although with higher freight costs and declining European demand, the API 4 could have an upward trajectory compared with the API 2.

Figure 2.16 Forward curves of API 2 (left) and API 4 (right), 2016

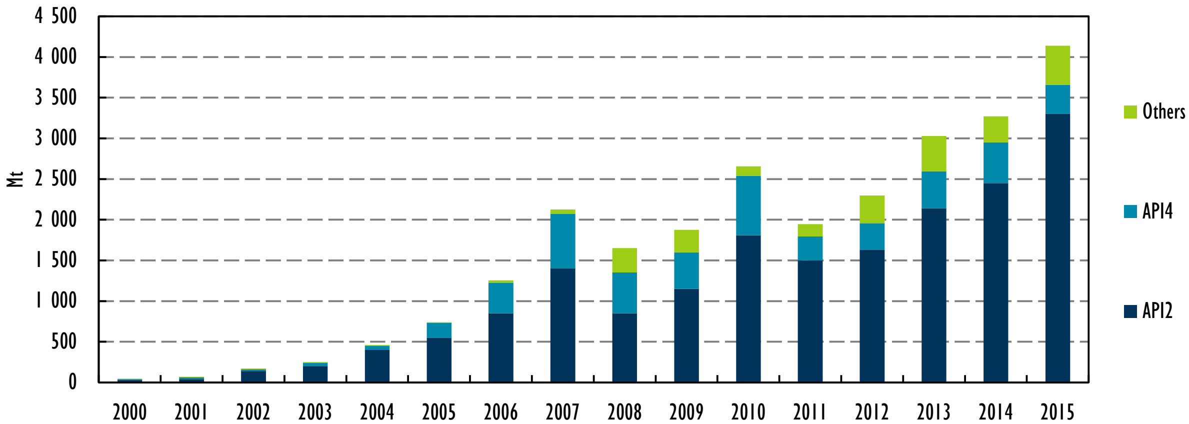


Note: Q1 = first quarter.
Source: IHS Energy (2016), *Coal McCloskey Price and Statistical Data*, https://connect.ihs.com/industry/coal.

Coal derivatives

The volume of financial coal derivatives traded continues to grow. The majority – around 80% – of the trade is API 2-based (over 3 000 Mt in 2015) despite decreasing physical volumes arriving at ARA ports. The volume of API 4 derivatives decreased in 2015 to around 360 Mt, roughly half the volume traded in 2010. Although still very small at only a few million tonnes annually, coking coal paper trade seems to be taking off, with increasing volumes and liquidity.

Figure 2.17 Trade volumes for coal derivatives, 2000-15



Note: The API 4 is the benchmark price reference for coal exported out of South Africa's Richards Bay terminal and is used in physical and over-the-counter (OTC) contracts (published through Argus/McCloskey's Coal Price Index service).
Source: IHS Energy (2016), *Coal McCloskey Price and Statistical Data*, https://connect.ihs.com/industry/coal.

Coal supply costs

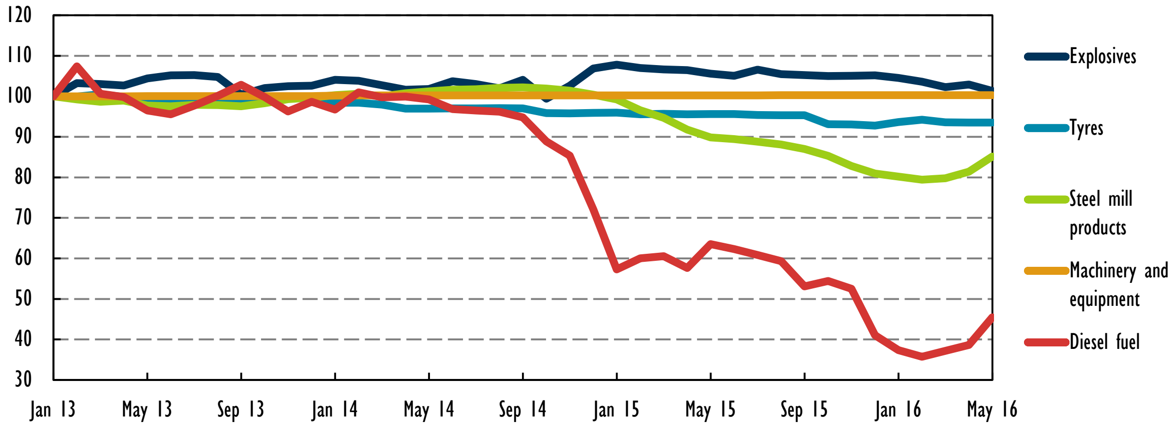
In comparison with oil and gas extraction, coal mining is much less capital-intensive. When analysing the cost structure of coal supply, the focus is therefore mainly on operating costs. Coal supply costs are composed of mining costs together with costs for inland transport, port fees, seaborne transport, and taxes and royalties. An additional cost factor is the currency exchange rate, which can have a substantial impact on the competitiveness of coal exporters because the bulk of variable costs are in local currencies.

Development of input factor prices

In most coal-exporting countries, mining costs constitute the largest share of total supply costs. Mining operating costs, also referred to as mining cash costs, comprise various input factors such as materials and labour, plus other costs such as royalties and outside services. The proportions of these components are different for each country and for each mine, owing to varying geological conditions and mining methods – in particular, surface and underground mining. Nevertheless, material costs usually account for more than half of a mine's cash costs. In countries with low labour costs (such as Indonesia, Colombia and South Africa), this share can be much larger. Materials such as diesel fuel, steel mill products, explosives, tyres and machinery are internationally traded commodities, and their prices follow global price trends. The prices of other inputs such as electricity and water, however, are subject to national factors.

Figure 2.18, which provides indexed prices of various internationally traded input materials in coal mining from January 2013 to May 2016, shows that, after a sharp fall in 2014, diesel prices stabilised briefly in the first quarter of 2015. They declined, however, for the remainder of 2015, resulting in an almost 30% difference between the beginning and the end of the year. Consequently, the decrease in diesel prices lowered mining costs, especially in open-cast mines where large numbers of diesel-powered vehicles are used; transportation costs were similarly reduced. Prices of steel mill products also fell sharply in 2015, the decrease in price amounting to almost 20 index points. (Note that both diesel prices and those of steel mill products showed strong increase during the first quarter of 2016.) In contrast, prices of the other material inputs (shown in Figure 2.18) remained more or less unchanged during 2015, and any changes over the period were less than 10 index points.

Figure 2.18 Indexed nominal prices of selected commodities used in coal mining

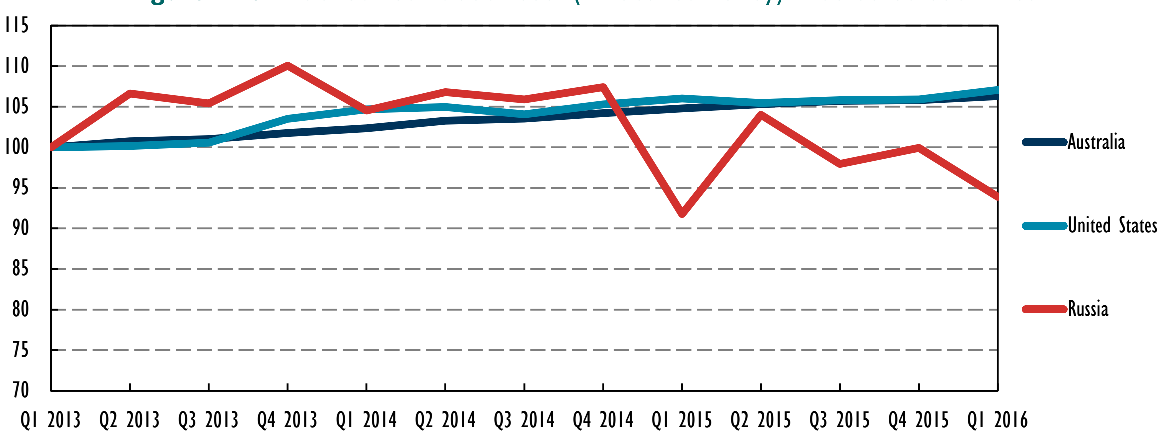


Source: US Bureau of Labour Statistics (2016a), Producer Price Data Commodity and Industry, www.bls.gov/data.

Labour costs are another major component of mining costs, responsible for 20% to 50% of the mining cash cost, depending on the country and the mining method. Highly developed countries such as the United States, Australia and Canada typically have higher labour costs than emerging countries such as South Africa, Colombia and Indonesia. The effect is partially suppressed, however, by the higher labour productivity in developed countries.

Figure 2.19 shows the development of indexed real labour costs in local currencies for selected countries: between 2013 and early 2016, labour costs in the United States and Australia increased 6% to 7%, whereas in Russia they were more volatile. Russian labour costs declined overall – especially from the last quarter of 2014 – corresponding to a 2% average quarterly decrease in wages. Although nominal labour costs in Russia actually increased during the period – in fact, they increased at a higher rate than did those of the United States and Australia – the high inflation rate in Russia resulted in lower real costs.

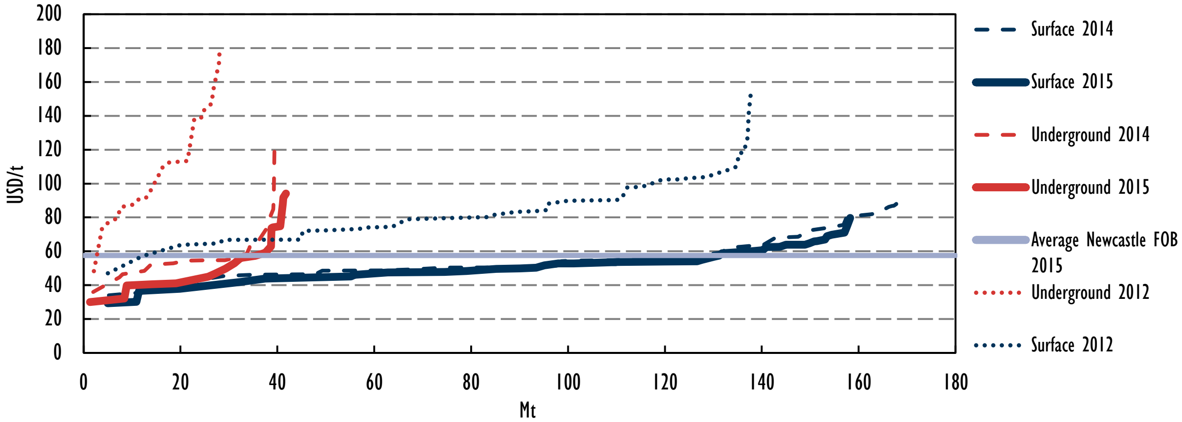
Figure 2.19 Indexed real labour cost (in local currency) in selected countries



Sources: Australian Bureau of Statistics (2016), *6345.0 – Wage Price Index*, Australia, March 2016, www.abs.gov.au/AUSSTATS/abs@.nsf/mf/6345.0/; US Bureau of Labour Statistics (2016b), *Employment, Hours, and Earnings from the Current Employment Statistics Survey (National), Industry: Coal Mining (Average Hourly Earnings of all Employees)*, www.bls.gov/data/; Russian Federation Federal State Statistics Service, *The Average Monthly Nominal Wage of Employees in the Whole Economy for the Subjects of the Russian Federation in 2013-2016*, www.gks.ru/wps/wcm/connect/rosstat_main/rosstat/ru/statistics/wages/.

Mining companies have pursued rigorous cost-cutting measures in recent years. Productivity gains have been achieved by increasing truck utilisation, improving coal washing and reducing delays at the coal preparation plant. Both Rio Tinto and BHP Billiton have announced further cost reduction targets. Increasing productivity in recent years has had two effects on the mining industry: lower costs and significantly flatter cost curves, which make a subsequent price recovery more difficult. This is a particularly important phenomenon in Australia, where some companies have cut production costs by almost half compared to 2010 levels.

Figure 2.20 Australian steam coal supply cost curves for surface and underground mines in 2012, 2014 and 2015



Note: Coal volumes, prices and costs are based on a calorific value of 6 000 kcal/kg.
Sources: Adapted from Wood MacKenzie (2016), *Coal* (private database), accessed July 2016; IHS Energy (2016), *Coal McCloskey Price and Statistical Data*, IHS, London, https://connect.ihs.com/industry/coal.

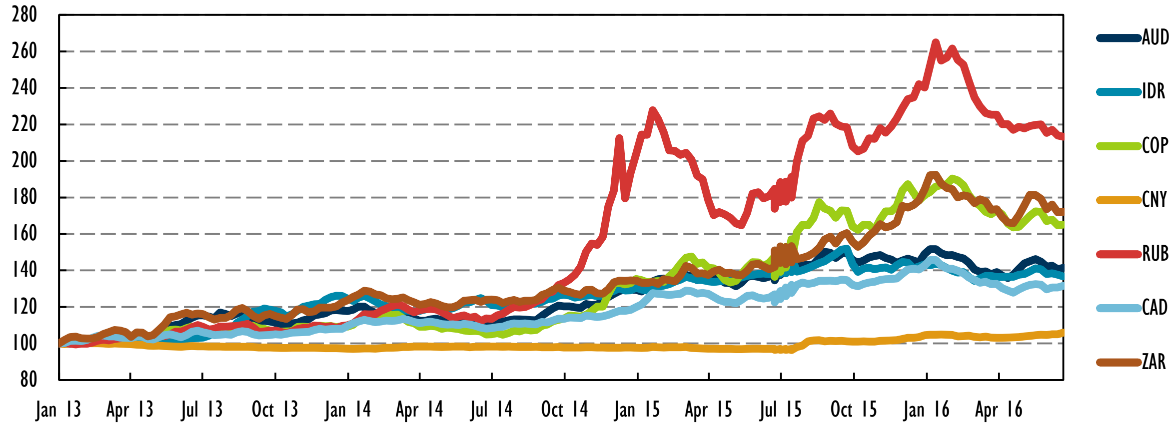
Figure 2.20, which charts supply costs of Australian steam coal for surface and underground mines during 2012-15, shows a strong decline in costs since 2012 in both types of mining. The decline in costs in 2015 was less pronounced, but because total capacity in surface mines has declined, Australian producers are gradually reaching their cost-cutting limit.

Currency exchange rates

The majority of the international coal trade is settled in USD, resulting in USD revenue streams for coal suppliers. However, many of the costs associated with coal supply, such as labour costs, railway tariffs, port charges and royalties, are settled in local currency. Currency exchange rates therefore directly affect the overall cost structure and international competitiveness of coal suppliers. Depreciation of the local currency against the US dollar, for instance, corresponds to an implicit decrease in supply costs for domestic producers, while appreciation of the local currency indirectly results in higher costs. Yet the costs of many imported inputs such as fuel and tyres increase with a depreciating local currency, and therefore lessen the impact of this effect. Similarly, coal buyers are also affected by fluctuations in the exchange rate: for example, depreciation of the local currency corresponds to higher procurement costs in USD. The currency exchange risks can be managed by coal suppliers as well as coal buyers by using a variety of available financial hedging instruments.

Figure 2.21 shows the indexed development of the US dollar against various selected currencies from 2013 to early 2016. The depreciation observed in 2014 for the selected currencies continued in 2015 with an even stronger trend for some. The Colombian peso (COP) depreciated sharply throughout 2015, whereas the Russian ruble (RUB) also depreciated overall but was more volatile. The economies of these two countries rely heavily on oil exports and were, as a result, strongly hit by the record low oil prices in 2015; Russia has additionally suffered from Western sanctions. Rates of domestic currency depreciation for other coal exporters such as South Africa, Indonesia, Canada and Australia were much higher in 2015 than in 2014. However, appreciation of the RUB and the COP corresponds with a slight increase in oil prices in the first quarter of 2016.

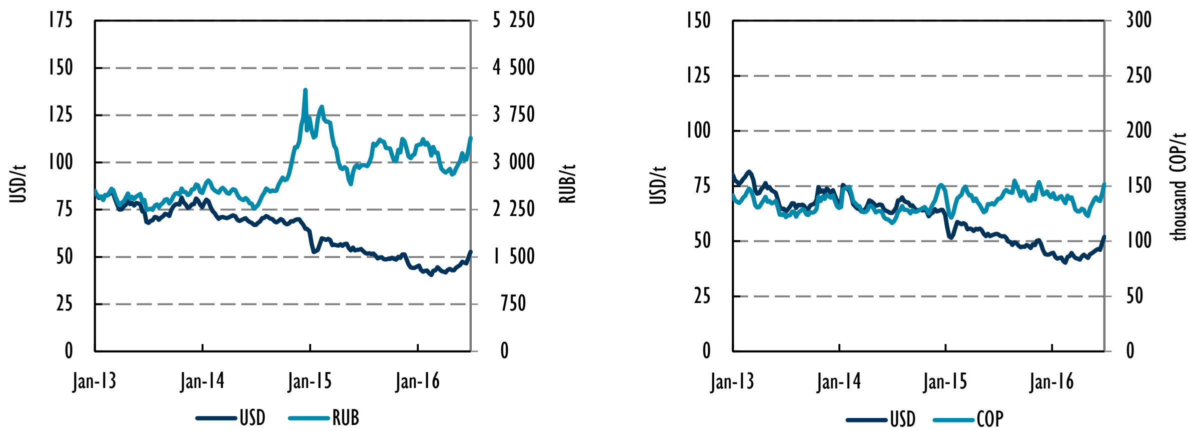
Figure 2.21 Indexed development of the USD against selected currencies



Notes: AUD = Australian dollar; IDR = Indonesian rupiah; CNY = Chinese Yuan renminbi; CAD = Canadian dollar; ZAR = South African rand; RUB = Russian ruble; COP = Colombian peso. The graph shows the indexed (Jan 2013 = 100) development of the US dollar against selected currencies, expressed as USD/domestic currency (e.g. USD/AUD). Therefore, a devaluation of the US dollar (USD 1 buys fewer units of another currency) results in a decline in the index.

The depreciation of the domestic currencies against the US dollar has partially compensated for the continued decline in international coal prices for the coal exporters in those countries. Figure 2.22 shows the indexed steam coal FOB prices in US dollars and in local currencies. In the figure on the left, the price marker declined almost continuously throughout 2014 and 2015. When expressed in Russian rubles, however, it roughly stabilises at a higher price after a sharp jump in 2014 and a subsequent fall in 2015. The competitiveness of Russian exporters has increased because inland railway transportation costs – which account for a substantial portion of total coal supply costs in Russia – are paid in rubles.

Figure 2.22 FOB steam coal prices in USD and local currency



Notes: RUB/t = Russian ruble per tonne; COP/t = Colombian peso per tonne.
Source: McCloskey (2016), *McCloskey Coal Reports 2010-2016*, http://cr.mccloskeycoal.com.

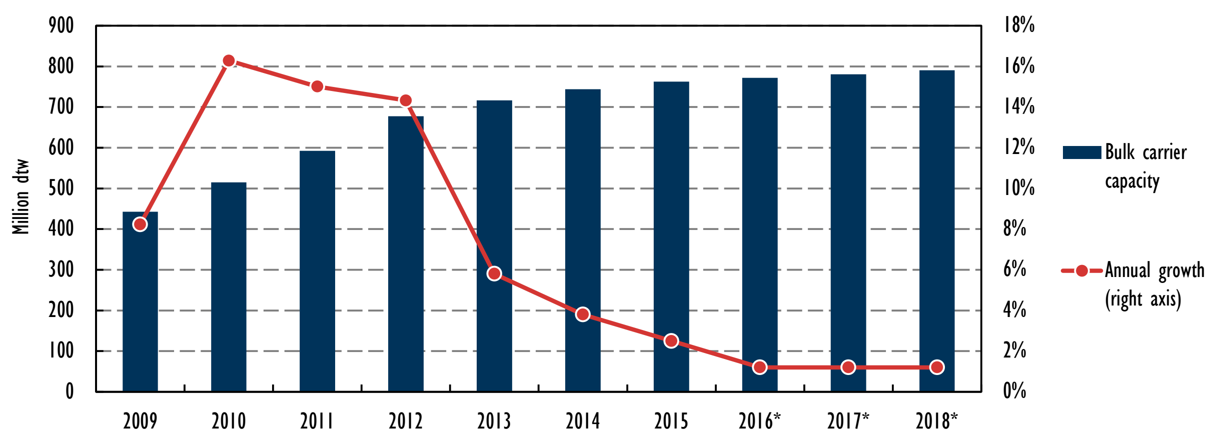
The figure on the right similarly shows that depreciation of the Colombian peso has compensated for the decrease in coal prices and the FOB price marker has remained more or less constant when expressed in Colombian pesos. The depreciation has therefore also increased the competitiveness of Colombian exporters. The effect in Colombia is less pronounced, however, as inland transport does not have the importance that it does in Russia.

Dry bulk shipping market

The seaborne dry bulk shipping market is a major component of the international coal supply chain since approximately 90% of internationally traded coal is transported by ship. Dry bulk freight vessels are used for the shipping, and they are categorised according to deadweight tonnage (dwt).[17] The four main vessel types are: Handysize (10 000 dwt to 60 000 dwt), Handymax/Supramax (35 000 dwt to 60 000 dwt), Panamax (60 000 dwt to 80 000 dwt) and Capesize (over 80 000 dwt).

About 30% of total seaborne dry bulk trade consists of coal, for which Panamax and Capesize are the commonly used vessel types. The dry bulk carrier supply is rather inflexible because it takes one to two years to build new bulk carriers. Moreover, shipyards are restricted in their production capacity because they have a limited number of assembly docks. This results in a rather cyclical pattern in the shipping industry. Development of the bulk carrier fleet is illustrated in Figure 2.23. Dry bulk capacity growth between 2010 and 2012 was strong owing to the remarkably high freight rates in 2008 (see Figure 2.24), which led to large investments in capacity. However, because of construction lead times, the ordered ships were only available after the 2008 global financial crisis when global trade had significantly contracted. The result was a large oversupply of bulk carrier capacity in the following years, and growth rates have decreased considerably; Capesize fleet capacity in particular decreased recently. Additionally, a high slippage rate has become the common norm, which means owners as well as investors are intentionally trying to delay new deliveries due to lacklustre market conditions. Despite these measures, new Capesize vessels are expected to be commissioned in 2016, and the freight rates are likely to stay low.

Figure 2.23 Bulk carrier fleet, 2009-18



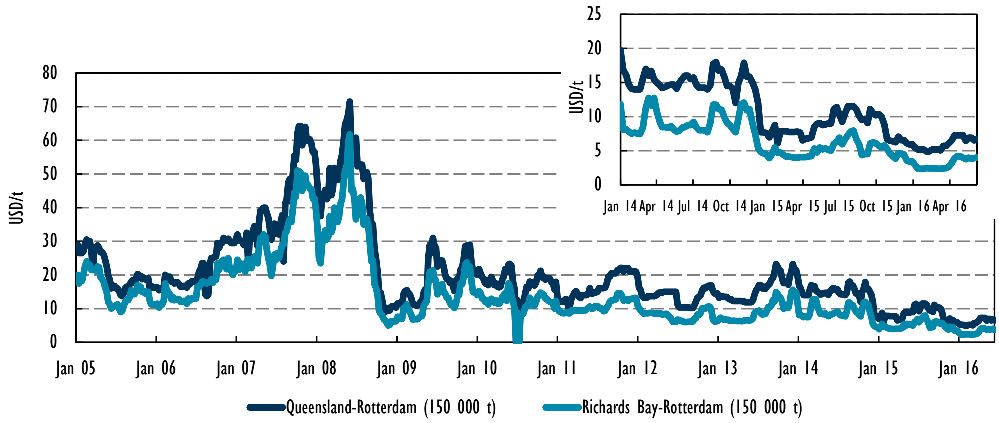
*Estimate.

Selected freight rates are charted in Figure 2.24. After a sharp decrease at the end of 2014,

[17] Deadweight tonnage is the mass that a ship can safely carry. It excludes the ship's weight, but includes fuel, water, crew and cargo.

freight rates continued declining in 2015 and 2016. The continued oversupply in the dry bulk market, combined with weak coal demand and lower bunker fuel costs, resulted in overall low freight rates. Rates to Rotterdam from Richards Bay and from Queensland were, on average, about 40% lower in 2015 than in 2014. Freight rates for Queensland-Rotterdam dropped from an average of USD 15/t to 8.5 USD/t, and those for Richards Bay-Rotterdam dropped from USD 9/t to USD 5/t; the decline continued in the first quarter of 2016. A result of these low rates, combined with a continued decrease in spreads, is that distant but less expensive exporters such as Colombia can compete in remote markets such as India with exporters located closer (e.g. South Africa and Australia).

Figure 2.24 Selected freight rates, 2005-16



Source: McCloskey (2016), *McCloskey Coal Reports 2010-2016*, http://cr.mccloskeycoal.com.

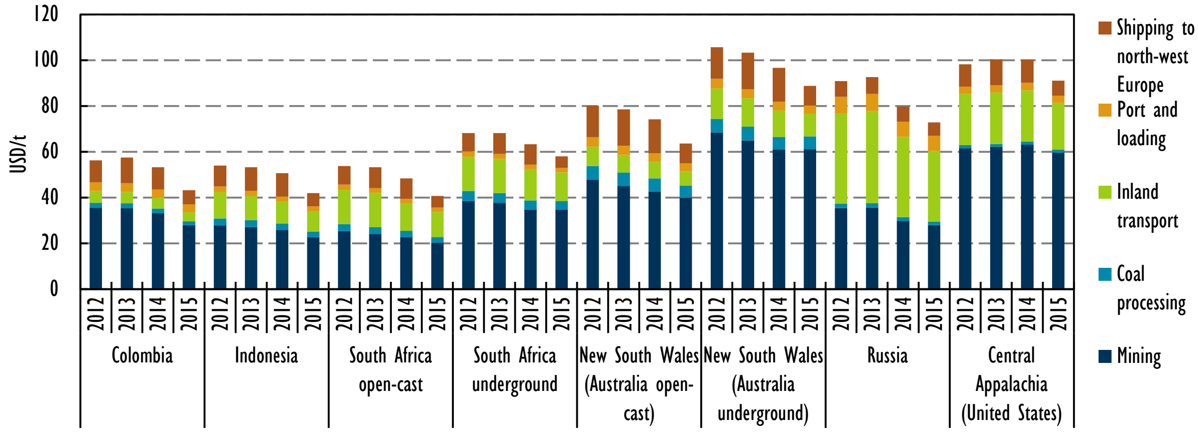
Development of coal supply costs

Coal supply costs continued to decrease in 2015 in the majority of coal-producing countries. Various factors contributed to this phenomenon: first, the US dollar remained strong in 2015 while most local currencies depreciated against it. Second, prices of the major input factors for coal mining either declined or stagnated. Diesel fuel prices declined especially sharply as a result of the drop in oil prices. Third, freight rates continued to decline strongly in 2015, and finally, given the low coal prices in the international market, companies continued implementing cost-cutting measures and efficiency improvements in addition to closing unprofitable high-cost mines.

These developments are illustrated in Figure 2.25, which depicts indicative steam coal supply costs to north-west Europe (ARA) for various exporters. To allow a purely cost-based comparison among different regions and coal exporters, royalties and taxes are not included. All the depicted countries had lower mining costs on average in 2015 for the reasons detailed above. Indonesia and Australia in particular had greatly reduced shipping costs due to declining freight rates, and Russia's inland transport costs dropped significantly. Rail-based inland transportation claims a large share of Russian coal supply costs due to the great average transportation distances. The strong decrease in diesel prices in 2015 therefore translated into substantial cost reductions.

Australian exporters have continued implementing cost-cutting measures in 2015 to combat decreasing prices. However, many mines are reaching their limits and the unprofitable ones are being shut down as a result. Mines in the United States are also having difficulties despite cost-cutting measures. A strong US dollar relative to other currencies in 2015 particularly undermined the competitiveness of exporters in the United States, resulting in undercutting by other exporters.

Figure 2.25 Indicative steam coal supply costs to north-west Europe by supply chain component and by country, 2012-15

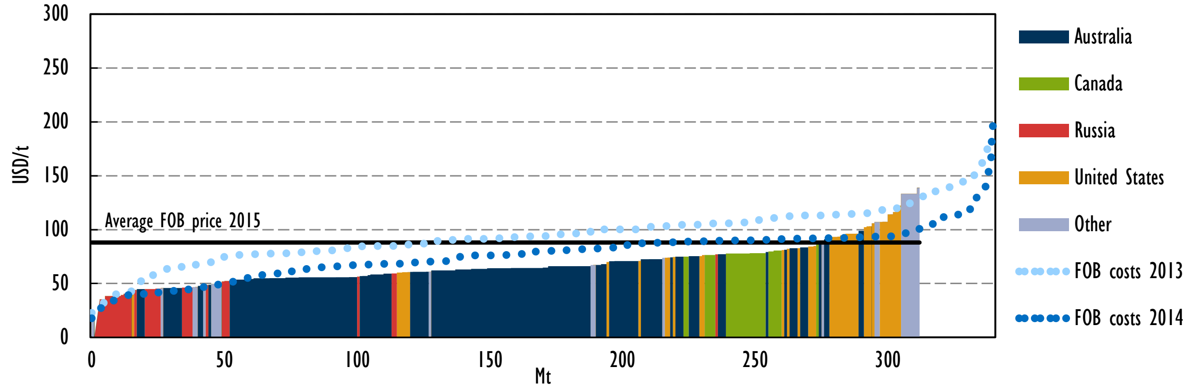


Note: Indicative supply costs in this figure do not include taxes and royalties.

In Figure 2.26 the indicative met coal FOB cost supply curve for selected countries as well as the indicative average FOB price in 2015 are presented. The indicative average price in 2015 was USD 88/t, down significantly from USD 106/t in 2014. In January 2015, met coal FOB prices ranged from USD 93/t to USD 114/t, depending on coal qualities; in December 2015, the price range was USD 64/t to USD 81/t. This significant drop in prices resulted mainly from weak Chinese met coal demand as a result of the global steel glut in addition to the met coal oversupply.

The continued decline in prices necessitated additional cost cutting, but where further cost cuts were not possible, mines were closed. The overall cost decline and the decrease in capacity from 2014 to 2015 are illustrated in Figure 2.26. Met coal exporters in Australia and Canada were particularly successful in cost cutting in 2015, whereas exporters in the United States with high-cost mines had a harder time, most of them having reached their limit. The dramatic depreciation of the Russian ruble placed Russian exporters in the first quartile of the global met coal supply curve in 2014, and this situation held in 2015 as well. However, compared with 2014, costs increased slightly due to extremely high Russian inflation rates in 2015. In Mozambique, transportation costs decreased after the Nacala corridor was cleared. However, as other producers reduced costs further, Mozambique has moved to the right in the supply curve.

Figure 2.26 Indicative met coal FOB cost curves and FOB prices, 2013-15



Notes: FOB prices are monthly averages derived from various price indices, such as Australian prime hard coking coal; Australian low-volatile PCI; US high-ash, high-volatile; and US low-volatile. Prices of certain met coal types can deviate from these indicative figures. FOB costs comprise variable production costs, processing, overburden removal, royalties, port usage and inland transportation.
Source: Adapted from Wood MacKenzie (2016), *Coal* (private database), accessed July 2016; McCloskey (2016), *McCloskey Coal Reports 2010-2015*, http://cr.mccloskeycoal.com.

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3. MEDIUM-TERM FORECAST OF DEMAND AND SUPPLY

Key findings

- **Global coal demand has plateaued, and sluggish growth over the outlook period (2015-21) is expected to bring demand in 2021 to just above the 2014 level.** Average annual growth of 0.6% from 2015 to 2021 is projected to increase demand by 196 million tonnes of coal-equivalent (Mtce), to 5 636 Mtce.

- **Coal demand in the People's Republic of China (hereafter "China") in 2021 is projected to be below the 2014 level.** Chinese coal consumption will be 2 816 Mtce by 2021 (compared with 2 896 Mtce consumed in 2014), with ups and downs driven by factors such as hydro production or power demand but in a structural decline.

- **The largest absolute growth in coal demand will be in India, but the greatest relative growth will be in Association of Southeast Asian Nations (ASEAN) countries.** Indian coal consumption is projected to increase 187 Mtce at an annual average growth rate of 5% by 2021. Demand in ASEAN countries is expected to grow an average of 7.2% each year, increasing by 85 Mtce over the outlook period.

- **India will become the second-largest steel producer, and later the second-largest blast furnace iron (BFI) producer over the outlook period, to consequently become the second-largest metallurgical (met) coal consumer.** Significant economic growth and large-scale infrastructure investments will be the main drivers of steel and BFI production, which will result in India's met coal demand increasing by 20 Mtce over the forecast period, overtaking Japanese demand and making India the second-largest met coal consumer in the world.

- **Coal demand in the United States and Europe continues its decline, which might even accelerate.** Low natural gas prices in the United States, as well as environmental and climate change policies in place in both the United States and Europe, will continue to reinforce declining coal demand in these two regions. Coal consumption is expected to drop to 475 Mtce by 2021 in the United States, and to 337 Mtce in Organisation for Economic Co-operation and Development (OECD) Europe.

- **The largest increase in coal production is expected to occur in India. Australian production will also increase, whereas Chinese production will remain flat.** In the context of growing demand, as well as ambitious plans to increase domestic production, Indian coal production is expected to grow an average of 5.8% per year to reach 536 Mtce by 2021, from 383 Mtce in 2015.

- **A remodelled coal industry is forecast to emerge in the United States after several mining company closures.** A slimmer and more competitive US coal industry will emerge in response to reduced demand. Despite lower costs, coal producers will struggle to compete in a shrinking market with prices kept in check by relatively inexpensive gas.

Methodology

In this chapter, coal demand is forecast for different coal types within two distinct groups: thermal coal and lignite, and met coal. The market-oriented approach accounts for met coal being priced and traded differently from thermal coal and lignite and used for different purpose. As with previous editions of this report, the International Energy Agency (IEA) provides forecasts for both OECD member and non-member economies.

The main determinants of coal usage are factors such as the relative price of coal and its substitutes (especially for power generation and industry), economic and population growth, and electrification rates. To account for these variables, demand forecasts in the Medium-Term Coal Market Report *(MTCMR)* employ country-specific econometric estimations – for instance, the elasticity of non-power thermal coal demand in relation to gross domestic product (GDP) or population growth. Demand projections specific to the country and coal type are obtained by using assumptions on various relevant parameters (e.g. GDP and population growth forecasts provided by the International Monetary Fund [IMF], fuel prices and average efficiency of coal-fired power plants). Drawing on the broad expertise of the IEA in primary energy markets enables consistent demand estimates that also recognise developments in other primary energy markets such as natural gas, renewable energies and crude oil. We consider policies already in force or very likely to be in force during the outlook period. With any change of government – including the US administration – there are often changes in policy that can have an impact on the energy sector and mix in that country and beyond. If these changes occur, the IEA will take these into account in future work.

Assumptions

As GDP growth is one of the major drivers of coal consumption, *MTCMR 2016* coal demand projections use the April 2016 GDP forecasts of the IMF (IMF, 2016). The IMF forecasts that the global economy will grow by 3.6% each year on average over the period 2016-21. The IMF April 2016 economic forecast for the period 2015-20 is 0.3 percentage points lower than its April 2015 forecast for the same period, indicating a slight downward revision of projections by the IMF. The IMF expects OECD non-member economies to grow strongly, with yearly average GDP growth of 4.8% during 2016-21. During this period, OECD member economies are expected to have a lower growth rate of 2% per year on average.

From 2016 to 2021, average annual GDP growth of 1.9% is projected for OECD Europe. OECD Americas is expected to grow at 2.3% per year during the same period, the United States being the main contributor. OECD Asia Oceania will similarly grow an average 1.5% per year; Korea is expected to have the highest growth in OECD Asia Oceania. In the previous IMF forecast, Japan was projected to have the second-highest GDP growth in OECD Asia Oceania, but in the April 2016 forecast Australia has surpassed Japan to now come second after Korea.

Among OECD non-member economies, India's GDP is expected to grow by 7.6% each year during 2016-21; this is roughly unchanged from the IMF April 2015 forecast for 2015-20. In contrast, the growth rate for China has decreased slightly, dropping from 6.3% in the April 2015 forecast (for 2015-20) to 6.1% in the April 2016 forecast (for 2016-21). Other developing Asian economies are also expected to grow substantially from 2016 to 2021, by 5% on average each year. The largest growth will be in Indonesia, followed by Malaysia and the Philippines.

African economies are expected to grow by 4.1% per year on average during 2016-21. This is a considerable drop from the 4.9% growth rate forecast in April 2015 for the period 2015-20. Average GDP growth rates have been revised slightly downward for Latin America (to 1.6% per year) and the Middle East (to 3.1% per year). In contrast, growth in non-OECD Europe/Eurasia was revised slightly upward to 1.7%.

In addition to changes in GDP, fuel price is a major factor affecting future coal demand. The price paths assumed for oil, gas and coal in this report are consistent with other IEA medium-term reports (IEA, 2016a; IEA, 2016b; IEA, 2016c). Forward curves are the basis for calculation, although some adjustments have been made.

Regarding oil, nominal IEA average import prices are assumed to reach about USD 60 per barrel in 2017, with a gradual but modest increase to 2021.

In the natural gas market, weak fundamentals and much lower oil prices have resulted not only in lower gas prices but in strong convergence across regional benchmarks. Looking ahead, well-supplied gas markets are set to keep spot prices under pressure while large imports of flexible liquefied natural gas (LNG) from the United States are expected to link North American prices with spot prices around the world. In Asia, gas prices will remain influenced by oil prices, although a period of oversupply, coupled with increasingly flexible LNG markets, is expected to gradually weaken this linkage. Average Henry Hub gas prices are projected to increase slightly to an average price of USD 2.9 per million British thermal units (MBtu) in 2021. In continental Europe, gas prices will continue to be based on a mix of spot and oil indexation, with the average price over the outlook period expected to be USD 5.3/MBtu. Over the outlook period, gas prices in OECD Asia Oceania (represented by Japan in Figure 3.1) are expected to remain higher than in Europe and the United States, reaching USD 8.1/MBtu by 2021. Furthermore, prices for carbon dioxide (CO_2) emission certificates in Europe are assumed to increase slightly to EUR 6 per tonne (t) by 2021.

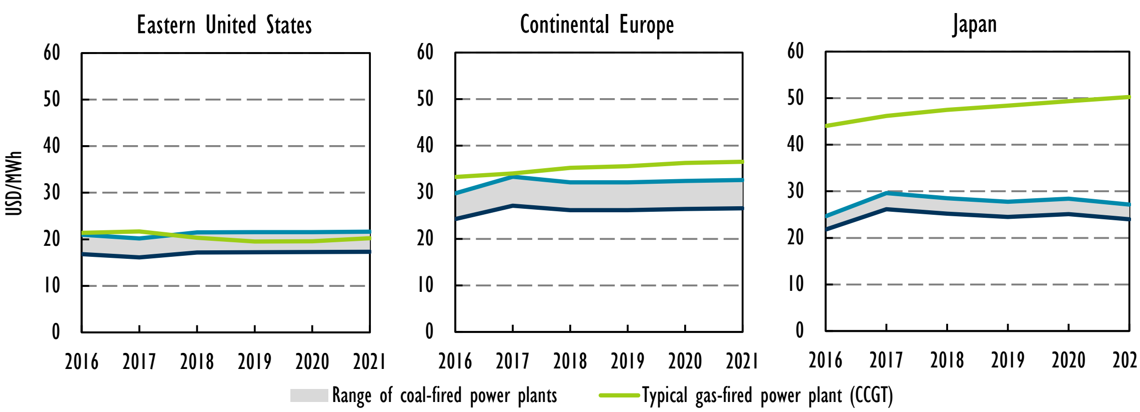
Thermal coal prices are expected to decline in 2017 and then remain relatively flat (note that current prices are around USD 15/t higher than the 2016 average). Indian coal prices are expected to narrow the gap with international prices.

The evolution of fuel prices strongly impacts the competitiveness of coal with other energy sources, especially natural gas. Using the price assumptions outlined above, marginal costs of electricity generation for coal-fired and gas-fired power plants have been calculated for the United States, continental Europe and Japan. Figure 3.1 illustrates a range of generation costs depending on coal power plant efficiency, alongside the costs of gas-fired power plants. Combined cycle gas turbine (CCGT) plants are considered to be the typical gas-fired power plant since they generally compete directly with coal-fired generation in the merit order of electricity markets, having the potential to displace them under favourable cost conditions.

Figure 3.1 shows that gas-fired plants will remain competitive with coal-fired plants in the United States over the outlook period because of abundant shale gas production and resultant low natural gas prices. Forward prices show that inter-fuel competition will be strong, and relative changes in coal and gas prices may result in significant changes in coal demand. In continental Europe, coal-fired plants are projected to remain more competitive. However, lower gas prices have reduced gas-fired generation costs considerably from previous years, increasing its competitiveness. In the summer of 2016, for instance, gas power plants were occasionally more competitive than coal plants, but volatile gas prices are expected to increase the frequency of such occasions over the outlook period. In Japan, the higher competitiveness of coal-fired generation is much more apparent owing to higher gas import prices and the lack of an emissions trading system.

Over the outlook period, coal-fired generation will remain competitive with gas-fired generation in most countries; nevertheless, gas and coal prices can vary significantly among different regions. For example, there are multiple gas hubs with different gas prices in the United States. Likewise, coal prices at power plants depend heavily on the availability of domestic coal close to the plants, as well as transportation costs. This brief analysis of the competitiveness of coal and gas in power generation therefore gives only a general view of the situation. A more detailed analysis should also address the local and regional factors mentioned.

Figure 3.1 Implied marginal costs of electricity generation for coal-fired and gas-fired power plants in different regions, 2016-21



Note: MWh = megawatt hour.

Global coal demand forecast

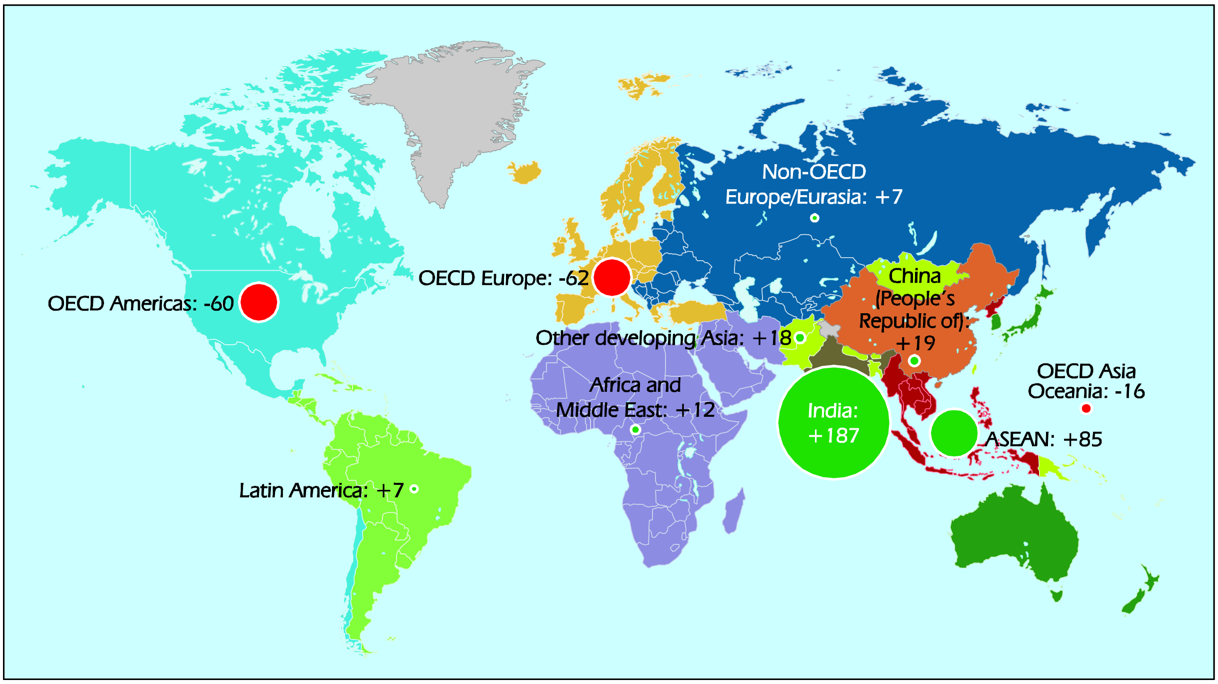
Global coal demand is forecast to increase by 196 Mtce during the period 2015-21, from 5 439 Mtce in 2015 to 5 636 Mtce in 2021. This corresponds to an average growth of 0.6% per year. Compared with the 2.5% average yearly growth during the last decade, a significant slowdown is expected. Furthermore, according to the IEA outlook for other energy sources, the share of coal in total primary energy consumption is expected to decline from 29% to 27% during the outlook period.

OECD non-member economies will be the key drivers of global coal demand growth, with an average yearly increase of 1.3%. India is the main contributor, showing the largest absolute demand growth (+187 Mtce) during the outlook period, or average annual growth of 5%. Conversely, Chinese demand is projected to remain relatively flat during the outlook period. It is expected to decrease marginally during the first half of the outlook period and then rise slightly again in the second half. Hence, total coal consumption of China in 2021 will be only 0.7% (+19 Mtce) higher than in 2015.

ASEAN countries show the largest relative demand growth, at a yearly average rate of 7.2% and an absolute increase of 85 Mtce over the outlook period. Demand in other developing countries in Asia will grow an average of 3% per year. Overall, the share of OECD non-members in global coal demand will amount to 79% in 2021.

Demand in OECD member countries is expected to decline by 1.8% per year on average during the forecast period, decreasing by 138 Mtce from 1 343 Mtce in 2015 to 1 205 Mtce in 2021. OECD Europe will experience the sharpest drop in coal consumption, with an average annual decline of 2.8% and an absolute decrease of 62 Mtce during the outlook period. OECD Americas follows closely behind at a decline rate of 1.8% and an absolute decrease of 60 Mtce, of which 48 Mtce comes from demand decline in the United States. Demand in OECD Asia Oceania will decrease slightly, by 16 Mtce over the outlook period, a marginal decline of 0.7% per year on average. Map 3.1 illustrates the absolute changes in coal demand over the outlook period.

Map 3.1 Incremental global coal demand (Mtce), 2015-21



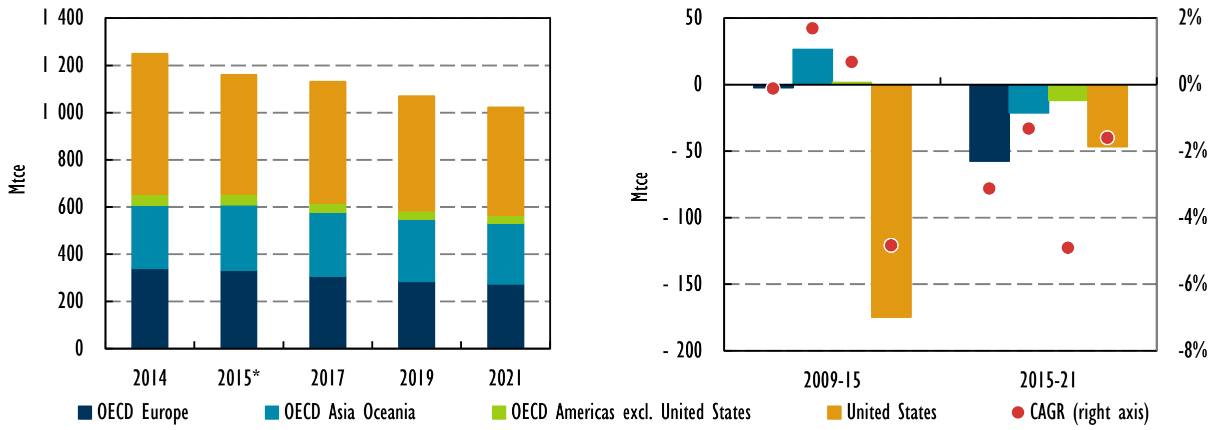
This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

OECD coal demand forecast, 2016-21

Thermal coal and lignite

Thermal coal and lignite will continue to account for 85% of total consumption during the outlook period. Total thermal coal and lignite demand is projected to decline at an average annual rate of 2.1%, from 1 160 Mtce in 2015 to 1 023 Mtce in 2021. Since 90% of thermal coal and lignite in OECD countries is consumed in the power sector, this reduction largely results from reduced coal-based electricity generation in the future.

Figure 3.2 Forecast thermal coal and lignite demand for OECD member countries



* Estimate.

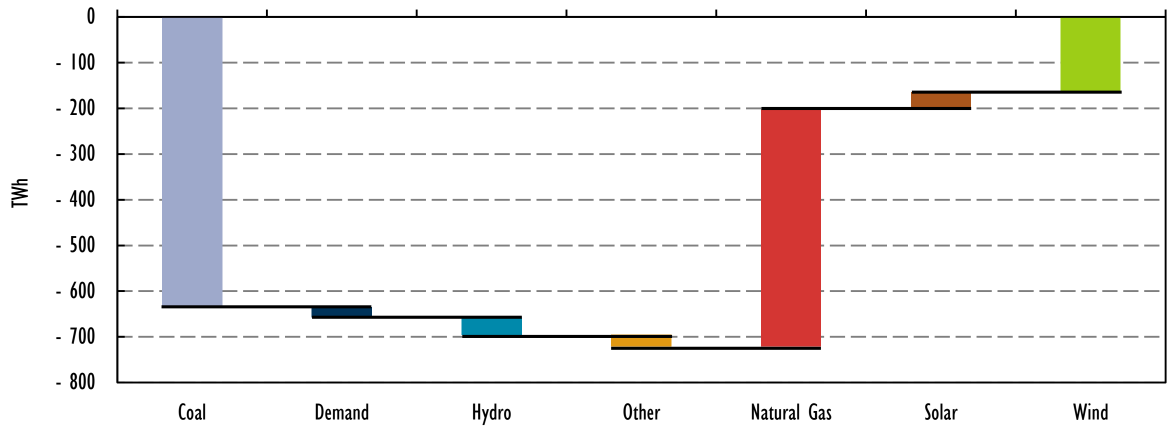
Note: CAGR = compound annual growth rate.

The **United States,** with a consumption of 505 Mtce, accounted for 43% of total OECD thermal and lignite demand in 2015. In our forecast, US demand is expected to increase slightly in 2017 to 474 Mtce after another big decline in 2016. Consumption will then decrease from 2017, dropping to 458 Mtce in 2021. An annual average decrease of 1.6% is thus forecast for the United States over the outlook period. The initial slight increase in demand and the continuous decline that follows can be explained by natural gas prices in the United States in 2015 and in the first quarter of 2016 being exceptionally low. They are expected to rebound in the next few years, resulting in a slight increase in coal demand. Since a part of coal-based power capacity is to be retired, however, demand will consequently decline after this initial increase.

In order to understand the dynamics of the power system in the United States, it is useful to analyse the trends during the last decade, when coal-based power generation dropped substantially and was mostly substituted with generation from natural gas (Figure 3.3). The fall in natural gas prices, resulting from increased shale gas production, played a major role in this switch from coal to gas in electricity generation. The coal power plants have traditionally covered base-load generation, but with increasing intermittent power from renewables, in addition to volatile gas prices, coal-based generation will become more variable in covering electricity demand. About 60 gigawatts (GW) of coal-based generation capacity are currently slated for decommissioning, and only the Kemper carbon capture and storage (CCS) coal project has been started. The Clean Power Plan, still in litigation, has the potential to significantly accelerate the retirement of coal power plants. Implementation of the Mercury and Air Toxics Standards (MATS) will also result in additional decommissioning during the outlook period. Our forecast assumes that Environmental Protection Agency (EPA) regulations already in place will continue to be in force during the outlook period and that Clean Power Plan, which is expected to have a substantial impact on coal demand after 2020, will be finally implemented.

Coal demand in other **OECD Americas** countries is also expected to decrease during the outlook period. Total thermal coal and lignite demand in OECD Americas is thus forecast to fall from 551 Mtce in 2015 to 492 Mtce in 2021, an average yearly decrease of 1.9%. The Emissions Performance Standard (EPS) adopted by Canada in 2012 strongly discourages additional coal-based generation capacity. The EPS entered fully into effect in July 2015 and requires any new coal power plant built in Canada to have the emissions level of a comparable natural gas generator, effectively making CCS mandatory. The 1-GW Bow City Power Station with CCS technology is therefore the only proposed new coal power plant.

Figure 3.3 Changes in US electricity demand and generation between 2006 and 2015



Note: TWh = terawatt hours.

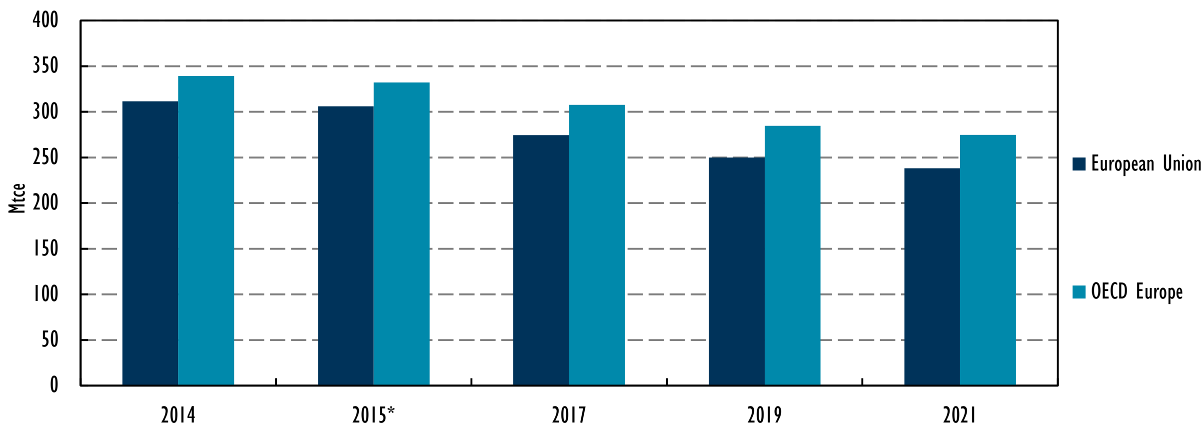
Thermal coal and lignite demand in **OECD Europe** is forecast to decrease sharply at an annual average rate of 3.1%, falling from 332 Mtce in 2015 to 275 Mtce in 2021. In the **European Union,** thermal coal and lignite demand will decline even more vigorously – from 306 Mtce in 2015 to 238 Mtce in 2021, an average annual reduction of 4.1%. Proposed new coal capacity already declined considerably in the European Union, owing to various factors such as the 2030 climate and energy framework of 2014, which set key targets for reducing greenhouse gas emissions, increasing renewable energy and improving energy efficiency by 2030. The market stability reserve, as part of the EU Emissions Trading System (EU ETS), will reduce surplus allowances starting in 2019, diminish CO_2 price volatility, and possibly raise CO_2 prices. Other factors involved in the sharp decline in new EU coal power plant investments include increasing public opposition and declining financial support by banks and financial institutions.

Germany is one of several countries in OECD Europe where there is new coal generation capacity (4 GW) under development. In 2015, the Moorburg power plant (1.7 GW) and Unit 9 of the Grosskraftwerk Mannheim (0.9 GW) started operation. Construction of Unit 4 of the Datteln power plant restarted after receiving the necessary permit from the district government. In May 2016, the European Commission approved Germany's scheme to take 2.7 GW of lignite-fired capacity out of the market to form a power capacity reserve. As a result of lignite mothballing and eventual closure, together with the German nuclear phase-out by 2022, utilisation of steam coal-fired power plants is expected to increase; steam coal consumption in Germany is therefore expected to decline more slowly than lignite consumption. A proposal to decommission all existing lignite-fired plants in Germany until 2040 is currently being debated by numerous parties and think tanks. This would put pressure on Germany, the largest coal consumer in Europe, to find alternatives to coal for electricity production. The government of the **United Kingdom** proposed to phase out coal-based generation by 2025, confirming the trend of declining coal demand that began in recent years.

The IMF forecasts strong economic growth in **Poland** – 3.5% per year on average through 2021 – which, considering some progress in energy efficiency, translates to electricity demand growth of just below 2%. It is assumed that additional renewable generation of almost 20 TWh, coming mainly from biomass and wind, will meet most of the increased demand. Coal generation will therefore increase only slightly overall, with a rise in hard coal and a slight decrease in lignite generation. The new capacity of 4.3 GW will use ultra-supercritical technology with higher efficiency and lower specific coal consumption than older plants, so hard coal consumption in power generation in 2021 will actually be the same as in 2015. Given the small reduction in non-power and lignite consumption, a 0.3% decline per year is forecast through 2021.

The difference in coal demand decline between OECD Europe (CAGR 3.1%) and the European Union (CAGR 4.1%) is mainly owing to Turkey, where 67 GW of additional coal-based generation capacity has been proposed to cover growing electricity demand. Other European countries with plans for large coal power plants include Bosnia and Herzegovina (3 GW), Serbia (3 GW) and Ukraine (1.3 GW). In practice, many of the planned coal power plants throughout the world have only been announced and have not proceeded to the construction stage.

Figure 3.4 Thermal coal and lignite demand forecast for OECD Europe and the European Union



* Estimate.

Thermal coal and lignite demand in **OECD Asia Oceania** will decrease by 1.3% per year on average during the outlook period, dropping from 277 Mtce in 2015 to 256 Mtce in 2021. The decrease is mainly due to a slight contraction in Japan, where it is expected that installed solar photovoltaic (PV) capacity will reach 61 GW by 2021, and assuming 17 GW of nuclear generation capacity restarting operation. After the reopening of Sendai nuclear power plant in 2015, Unit 3 of Ikata also restarted operation in August 2016. Takahama 3 and 4 were similarly restarted in January and February 2016, but were later closed down in March in compliance with a court injunction.

In addition to the recent restart of nuclear power plants in **Japan**, the 2 GW of coal-fired capacity currently under construction is expected to be commissioned during the outlook period. A further 21 GW of additional coal-fired capacity has been announced, the majority of it high-efficient, which is usually dispatched for more hours than subcritical. In 2014, for example, ultra-supercritical and supercritical plants operated for 7 360 full-load hours, whereas subcritical plants ran for

6 130 hours. The new coal-fired plants with higher efficiencies will primarily replace older subcritical plants, resulting in decreased coal consumption for the same amount of electricity generated.

Demand for thermal coal and lignite in **Korea** is expected to increase slightly during the outlook period. Despite only a marginal increase in power demand, Korea has announced 10 GW of new coal-fired generation projects in addition to the almost 9 GW of capacity already under construction, with 3.8 GW being cancelled recently. Part of this capacity will be offset by the retirement of old plants. Coal-fired power generation, the main driver of coal demand, is therefore not expected to increase significantly. In addition, LNG forward prices over the outlook period are quite low for Korea, in contrast to relatively high carbon prices. Natural gas is therefore expected to become more competitive with coal and could substitute for some coal as a result.

In November 2015, Engie announced the closure of lignite-fuelled Hazelwood (1.6 GW) in Victoria, Australia. Hazelwood's electricity is expected to be replaced by hard coal – mostly in New South Wales – and gas generation, thus reducing coal demand by 2 Mtce. On the other hand, the closure of Portland Aluminium Smelter would reduce power demand equivalent to almost 40% of the electricity produced by Hazelwood.

Table 3.1 Coal-fired power plants currently under construction in Korea

Plant	Unit	Capacity (MW)	Commissioning
Dangjin	10	1 000	2016*
Yeosu	1	350	2016*
Samcheok	1	1 000	2016*
Shin Boryeong	1	1 000	2016*
Bukpyeong	1, 2	2 x 600	2016*
Samcheok Green	2	1 000	2017
Taean	9, 10	2 x 1 050	2017
Shin Boryeong	2	1 000	2017
Total		**8 650**	

*At the time of writing, these power plants had not yet started commercial operation.
Note: MW = megawatt.

Met coal

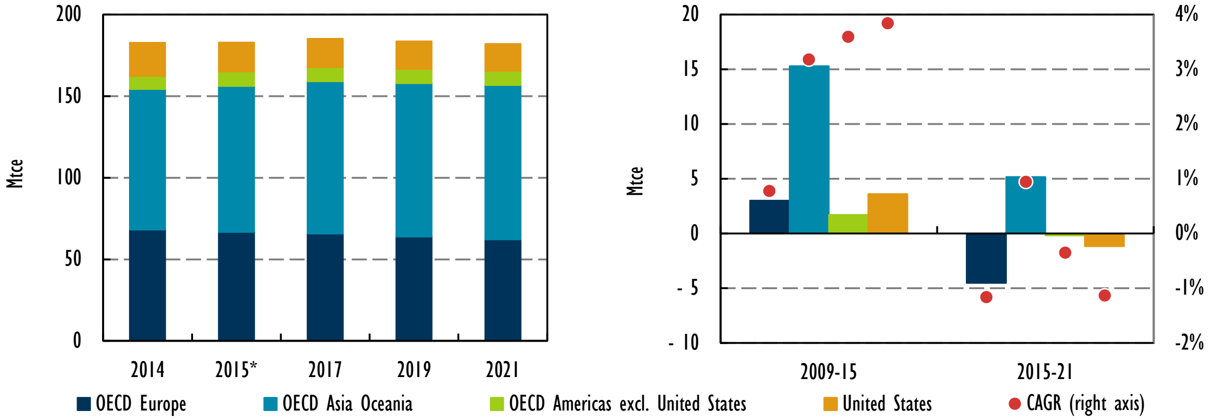
Met coal demand in OECD member countries overall is expected to remain relatively flat during the outlook period, dropping very slightly from 183 Mtce in 2015 to 182 Mtce in 2021. Demand in OECD Americas will decrease slightly, while demand decline in OECD Europe will be more pronounced. Met coal demand in OECD Asia Oceania, however, is expected to increase slightly during the outlook period.

In OECD Americas, met coal demand will decrease from 27 Mtce in 2015 to 25 Mtce in 2021, an average decline of 0.9% per year. US met coal demand specifically will similarly decline 1.1% per year on average, dropping from 2015 consumption of 18 Mtce to 17 Mtce at the end of the outlook period.

Met coal demand in OECD Europe will decrease substantially, at an average rate of 1.2% per year. Consumption is thus expected to fall from 67 Mtce in 2015 to 62 Mtce in 2021. Met coal demand in mature economies such as Germany and the United Kingdom will decrease as a result of declining steel production. In contrast with the growth of recent years, demand in Turkey is expected to stay roughly unchanged during the outlook period because of slower economic growth.

Met coal demand in OECD Asia Oceania is expected to increase from 89 Mtce in 2015 to 95 Mtce in 2021 at an annual average growth rate of 0.9%. Met coal consumption in Japan is expected to increase slightly, but the growth in met coal demand in Korea is more pronounced owing to the higher rate of economic growth.

Figure 3.5 Forecast met coal demand for OECD member countries

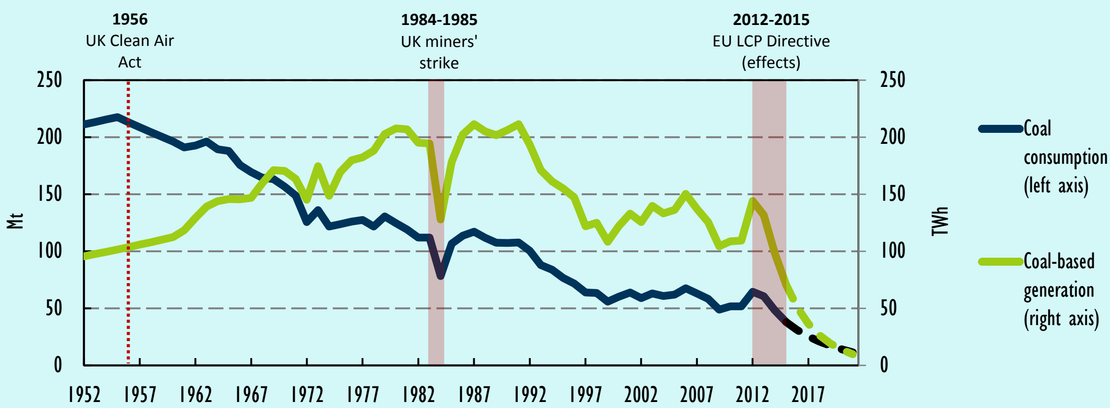


* Estimate.

Box 3.1 A farewell to coal

Great Britain, the country where the coal-based Industrial Revolution was born, seems to now be one of the pioneers in the return journey away from coal, with significant milestones already passed. In 2015, for instance, the last underground mine in the United Kingdom, the Kellingley colliery, closed. Although coal mining has not been a large business in the United Kingdom for decades, the closure symbolises the end of an era.

Figure 3.6 Evolution of coal-based generation and coal consumption in the United Kingdom



Box 3.1 A farewell to coal (continued)

In November 2015, the UK government removed the GBP 1 billion capital reserved to build a CCS power plant. While CCS has lost momentum in recent years, not only in the United Kingdom but more widely in Europe, such a decision seems to mark a radical policy change, from a low-carbon power mix to no coal whatsoever. Also in 2015, the Energy Secretary proposed an end to coal power in the United Kingdom by 2025 and to restrict its use from 2023 onwards.

In March 2016, the Longannet coal power plant stopped operations, marking the end of coal power generation in Scotland, where coal was once the dominant source of power generation. Two weeks later, Ferrybridge also closed. The additions of Rugeley, which closed during the year, and Fiddlers Ferry, which will be closed in March 2017, means that almost half of the coal generation capacity that existed in 2012 had been decommissioned by the end of 2015 – and more than two-thirds has already been decommissioned.

The transition will be supported by some type of remuneration mechanism to guarantee sufficient generation capacity at times of high demand and low renewable generation. The government also implemented the Demand Turn Up scheme to encourage electricity consumption when variable renewable energy (VRE) production is high, to balance the system.

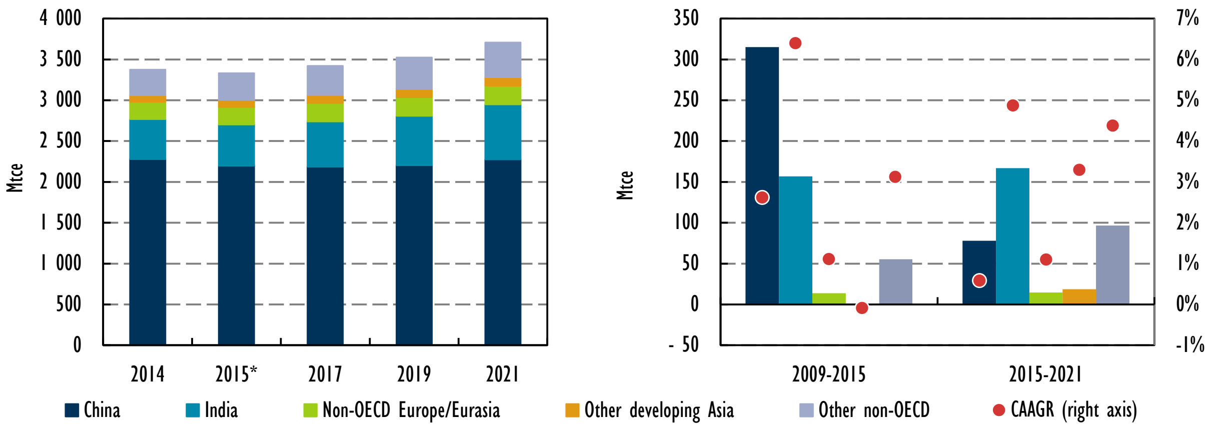
In short, although the end of coal in the United Kingdom appears inevitable, the policies, technologies and cost of the transition remain uncertain.

OECD non-member coal demand forecast, 2016-21

Thermal coal and lignite

In OECD non-member economies, thermal coal and lignite demand is projected to increase an average 1.8% per year throughout the outlook period, from 3 333 Mtce in 2015 to 3 708 Mtce in 2021. The power sector will continue to be the main driver of demand.

Figure 3.7 Forecast thermal coal and lignite demand for OECD non-member economies



* Estimate.

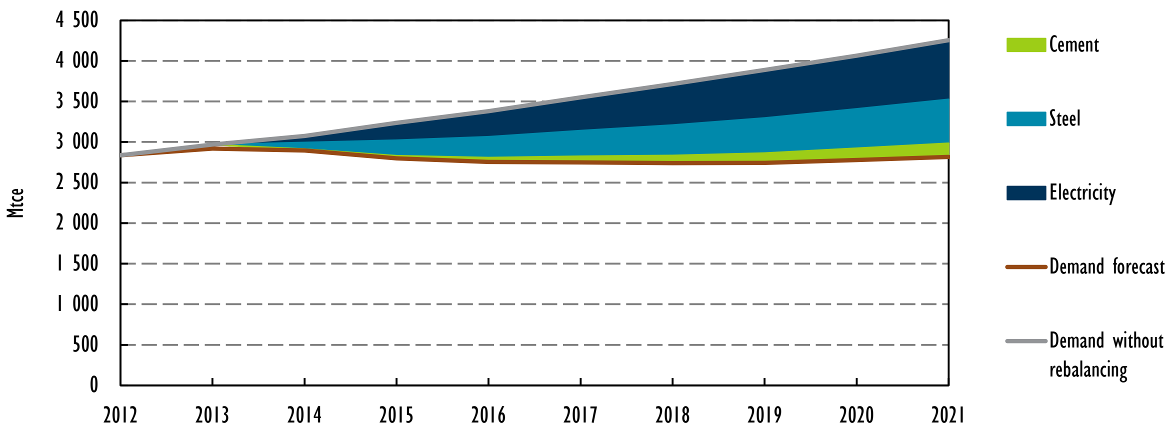
China

China continues to have the largest thermal coal and lignite consumption of OECD non-member economies throughout the outlook period. The increase in Chinese demand will, however, be small:

at an average yearly growth rate of 0.6%, it is expected that consumption will rise from 2 197 Mtce in 2015 to 2 275 Mtce in 2021. China's share of OECD non-member consumption will consequently fall in 2021 to around 61% as demand grows significantly in India and ASEAN countries during the period.

One reason for declining Chinese demand growth is decelerating economic growth: China's GDP growth during the outlook period is projected to be 6.1%, continuing the declining trend of recent years. Another reason is the diversification policy from coal that the Chinese government has implemented, which means big development of hydro, nuclear, wind and solar. Last, but not least, the rebalancing of the Chinese economy, as shown in Figure 3.8, which compares the *MTCMR* actual forecast and the hypothetical demand using historical GDP elasticities for power, steel and cement consumption, indicating that Chinese economic rebalancing will curb coal demand growth significantly. However, economic rebalancing means the services sector's share in GDP will increase as the economy becomes consumption-based rather than investment-led. This is relevant for coal, given that industry is an intensive consumer of electricity, and steel and cement production are coal-intensive. Without rebalancing – and assuming non-coal sources of electricity unchanged – Chinese coal consumption would be expected to grow significantly over the outlook period. However, actual demand forecast is relatively flat over the outlook period. The Chinese government, by instituting policies on a wide array of issues associated with coal use in the country, has a considerable influence on coal consumption. Main goals of the government include diversifying the Chinese energy mix, lowering energy intensity and reducing air pollution. To this end, China's National Energy Administration (NEA) released its clean-coal action plan in 2015, which aims to improve overall efficiencies and reduce particulate emissions of the coal-fired generation fleet.

Figure 3.8 Effect of economic rebalancing on coal demand in China

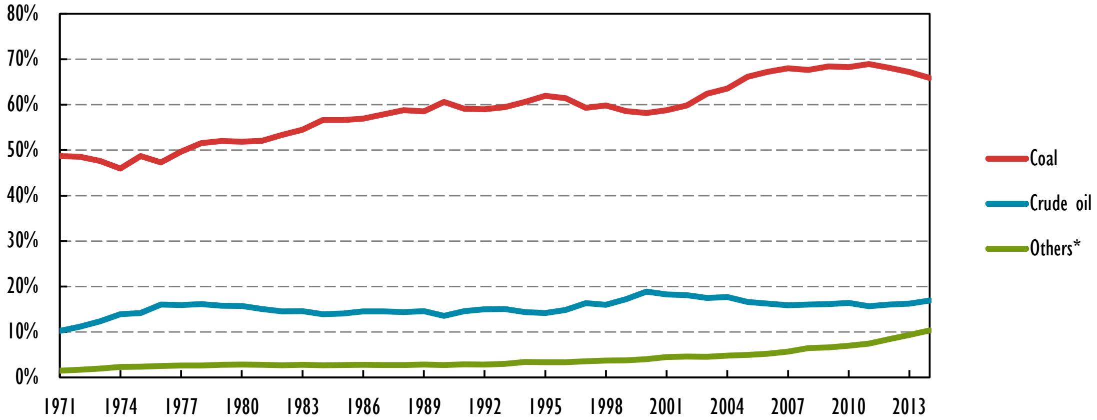


A significant expansion of coal conversion (i.e. coal-to-gas, coal-to-liquid and coal-to-olefin) capacities is expected, reaching about 21 billion cubic metres (bcm) of coal-to-gas and 12 million tonnes (Mt) of coal-to-liquid capacity commissioned by 2021. Additional demand from coal conversion projects is expected to contribute over 90 Mtce to overall coal demand during the outlook period.

Installed hydropower capacity in China was 320 GW at the end of 2015, making up about 20% of total generation capacity. Because of this large amount of hydro capacity, variations in hydro generation (which is weather-dependent) will affect coal-fired generation and coal demand in

China. Hydropower capacity expansion, which has been responsible for significant curtailment of coal power generation growth, will decelerate in China over the outlook period due to geographical constraints.[18] This will be one of the factors contributing to increased coal-fired generation by the end of the outlook period.

Figure 3.9 Shares of various energy sources in total primary energy supply in China



* Includes natural gas, nuclear power, hydropower and renewables.

Box 3.2 Coal power plant bubble in China: Why is this happening?

After a decade of striking growth, coal power generation in China declined in 2014 and 2015, and will remain more or less flat in 2016. Moreover, prospects for coal generation growth in the years to come are limited. Recent strong government policies supporting large investments in hydro, nuclear, wind and solar PV, as well as energy efficiency, are expected to continue given climate change commitments, air pollution concerns and weaker power demand growth.

Construction of coal power plants slackened in 2014, with capacity additions below 40 GW for the first time in many years, but in 2015 construction activity recovered to previous levels and a further 70 GW were commissioned, with a similar trend in 2016. Between January and April 2016 alone, 22 GW of coal power plants were commissioned in China. Although decommissioning partially offsets new capacity, retirement rates of less than 5 GW per year have little relevancy. While the plants commissioned today are the result of decisions made several years ago, new orders have not stopped: low load factors (utilisation declined from 5 300 hours in 2011 to 4 300 hours in 2015, with a further decline in 2016) are not impacting the decision to build more coal power plants. Furthermore, in 2015, during the greatest-ever decline in coal power generation in China, not only did permits and orders for new coal plants not decrease, but they accelerated, with orders for more than 100 coal plants (around 70 GW) in that year.

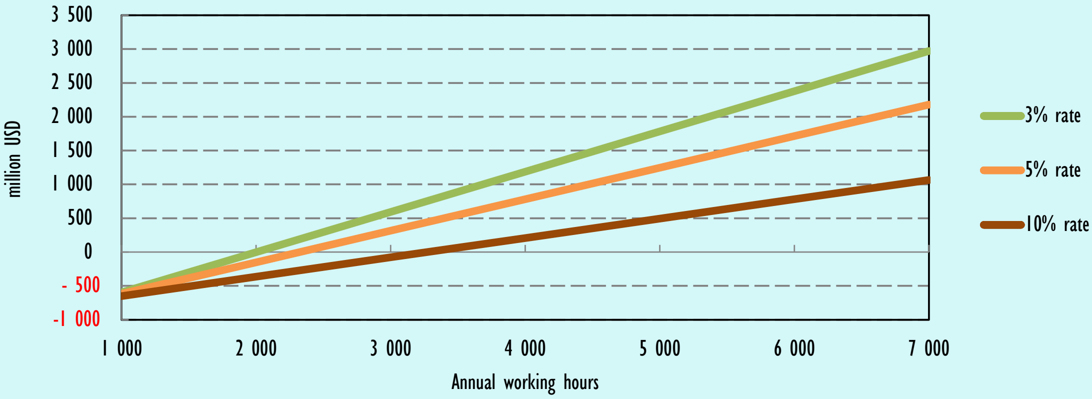
Electricity peak demand is not the reason for this development, as there is enough capacity to meet the peak demand; actually, current capacity exceeds peak demand by 40%. There is no doubt that policies play an important role: the authority to approve coal plants was transferred from the central government to local provincial authorities in October 2014. Coal power plant construction is a good way to enhance local economies and create jobs, and thus increase GDP growth. In addition, overnight costs of coal power plants in China are very low compared with international standards (as low as USD 600

[18] The number of undeveloped, suitable sites decreases with each additional plant built.

Box 3.2 Coal power plant bubble in China: Why is this happening? (continued)

per kilowatt [kW]), and most government-backed Chinese utilities have easy access to financing and low costs – a substantial advantage for a highly capital-intensive investment such as a coal power plant. What is more, state-owned Chinese utilities can invest their profits with less restriction than traditional utilities. Last, but not least, the economics of Chinese plants are very favourable. In Figure 3.10, in which a conservative USD 700/kW is assumed, investments in coal power plants have positive net present values even at very low load factors.

Figure 3.10 Net present value of Chinese coal power plants at different parameters



Note: The graph assumes investment costs of USD 700/kW, an electricity tariff of CNY 350/MWh and a coal price of CNY 452/t.

The economic feasibility of a coal power plant does not necessarily guarantee its construction, however. A positive net present value (NPV) does not automatically mean that a company will go ahead with the investment, as the internal rate of return, opportunity costs, etc., are more important than NPV in the investment decision. Also, as there is no real economic sense in building more coal power plants, Chinese authorities will somehow dissuade or stop construction of new coal power plants in the near future. One final note to put things into perspective is that, although 70 GW would be a large amount of additional capacity in any other country, in China, where coal power generation capacity is over 900 GW, it is perceived as much smaller.

India

The Indian economy is expected to grow an average of 7.6% each year over the outlook period. Approximately 245 million people live without electricity in India and the government has launched the "24 x 7 Power for All" initiative to end it. At the same time, programmes like Make in India, targeting the localisation of important manufacturing industries in India, are expected to keep pressure on electricity demand. As a result, coal demand growth in India will be driven mainly by rising consumption in the power sector. In fact, the UDAY scheme, targeting the end of discoms economic distress, has the potential to trigger power demand.[19] Around 72 GW of coal-based generation capacity is currently under construction and over 200 GW of additional capacity is planned. Throughout the outlook period, the steel and cement sectors will also grow significantly to become the other major contributors to demand increase.

[19] Ujwal DISCOM Assurance Yojana (UDAY) is the financial turnaround and revivial package for electricity distribution companies of India (DISCOMS).

Demand for thermal coal and lignite is expected to increase from 505 Mtce in 2015 to 672 Mtce in 2021, an annual average growth of 4.9%. Consumption in the power sector will similarly grow 5.4% on average each year, reaching 445 Mtce by the end of the outlook period. It should be noted that the Indian government's Ultra Mega Power Projects programme, aimed at meeting the electrification needs of the country, is not working well. Of the 16 coal power plants (4 GW each) planned in 2006, only two have been commissioned so far – the Mundra plant and the Sasan project. The second round of auctions was unsuccessful due to lack of interest by investors, concerned that the investment risks were unequally shared between the generators and the distribution companies. The government decided to pursue a build-own-operate (BOO) model as a result, and changed the bidding scheme accordingly. In December 2015, the Indian government approved its coal gasification policy and plans to build underground coal gasification projects: the Talcher fertiliser plant, using coal gasification technology, is expected to become operational during the outlook period, and a coal gasification plant in Chhatisgarh is also planned.

Other Asia including ASEAN

Thermal coal and lignite demand in ASEAN countries is expected to grow by 6.9% on average each year during the outlook period, increasing from 162 Mtce in 2015 to 241 Mtce in 2021. ASEAN countries will thus have the largest relative growth of all country groupings. The main driver for growth will continue to be the power sector, with a large number of power plants under construction and a significant amount of additional capacity planned.

Indonesian demand for thermal coal and lignite is expected to grow strongly during the outlook period owing to a sharp rise in coal-based generation. President Joko Widodo had initiated ambitious plans to build 35 GW of additional generation capacity by 2019, of which 20 GW is coal-fired, but in May 2016 the president called for a review of the programme because progress has been slower than expected. To resolve this delay, Widodo aims to grant regional administrations additional authority to hasten decision making and approve acquisition stages for power plants more quickly. The 2-GW Batang plant, delayed for years because of land acquisition issues, finally reached financial closure in June 2016 and is expected to be commissioned in 2020. Around 9 GW of additional coal-fired capacity is expected to come on line during the outlook period.

Table 3.2 Major coal-fired power plants currently under construction in Indonesia

Plant	Capacity (MW)	Technology	Commissioning
Tenayan Raya	220	Subcritical	2016*
Kaltim Teluk Balikpapan	220	Subcritical	2016*
Celukan Bawang	140	Subcritical	2016*
Sumbagut	230	Subcritical	2016*
Banten Serang	670	Supercritical	2017
Parit Baru	100	Subcritical	2017
Sulsel Barru-2	100	Subcritical	2017
Tabalong Power	200	Subcritical	2018
Jawa Tengah	2 000	Ultra-supercritical	2019
Total	**3 880**		

*At the time of writing, these power plants had not yet started commercial operation.

Box 3.3 The hunger for electricity in emerging economies

Discussions of future energy and power demand growth are often focused on India and China because of their extremely large populations and their economic potential. However, several other countries have also had impressive population expansions in recent decades, so growth in energy demand is potentially huge. Figure 3.11 illustrates electricity consumption at different levels of development* for Indonesia, Pakistan, Nigeria, Bangladesh, the Philippines, Ethiopia and Viet Nam. All these countries currently have populations of over 90 million, but Indonesia's is the largest at over 250 million, followed by Pakistan at 189 million and Nigeria at 182 million. All the countries have low electricity demand per capita compared with developed countries (more than 10 000 kWh per person in United States): Ethiopia has the lowest per capita electricity consumption at only 61 kilowatt hours (kWh) per person per year, while Viet Nam has the highest at 1 244 kWh per person.

Figure 3.11 Potential electricity demand in emerging economies at various development levels

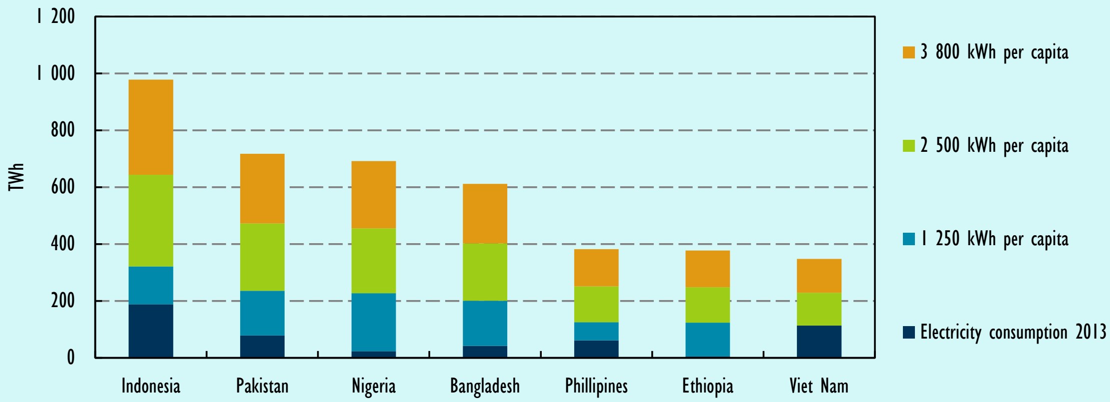


Figure 3.11 not only shows current electricity demand, but potential consumption correlated with economic advances in each country. The aggregate electricity demand of all countries in 2014 amounts to 550 TWh; if electricity consumption per capita increases to 1 250 kWh per year – comparable to current consumption in Viet Nam – the total yearly combined demand of these countries increases by over 800 TWh, which is much less than total Indian electricity consumption in 2014. If electricity consumption per capita increases to 2 500 kWh per year, comparable to that of Thailand, another increase of 1 350 TWh would occur, for a total consumption of 2 700 TWh. At this level, these countries would be consuming almost as much electricity as the European Union did in 2014. With a specific electricity consumption of 3 800 kWh, comparable to current Chinese consumption, the total demand shown in Figure 3.11 would increase to more than 4 100 TWh – more than global hydro production and almost four times wind and solar production, or above current US electricity demand and almost as high as Chinese demand in 2014.

Although the trends represented in Figure 3.11 are improbable, this graph demonstrates that demands for electricity can be immense, especially if the populations of these countries continue to grow. The scale of the challenge posed by development of these countries, including universal electrification and industrial and infrastructure development, is considerable.

* Although it is recognised that electricity consumption is not the only indicator of development.

Demand in Viet Nam is also expected to increase significantly during the outlook period, with approximately 17 GW of coal-fired capacity to be commissioned by 2021. In Malaysia, demand for steam coal and lignite increases substantially as 2.5 GW of coal-fired capacity become operational during the outlook period. Similarly, the Philippines will have significant demand growth owing to 5 GW of capacity coming on line during the period. Demand in other Asian non-ASEAN developing markets is also expected to grow, albeit at a lower yearly growth rate of 3.3% on average.

Bangladesh, for instance, has announced plans to commission 24 GW of coal-fired capacity by 2022, and Pakistan similarly considers expanding its coal-fired generation capacity by 20 GW. Coal-fired plants under construction in Pakistan include the Sahiwal coal power station (1 320 MW), the Port Qasim coal power project (1 320 MW) and the Thar project, which consists of a lignite mine and power plant (2 x 330 MW), with subsequent expansions.

It is interesting that India, Indonesia, Pakistan and Viet Nam combined account for one-quarter of the world's population, but consume a meagre 8% of global electricity. To bring the population-consumption ratio in line with Chinese electricity consumption levels would mean increasing power generation by around 5 500 TWh – more than global natural gas-fired power production, twice current global nuclear production, or five times global wind and solar generation combined. What is more, these four countries are endowed with abundant coal reserves: hard coal in India, Indonesia and Viet Nam, and lignite in Indonesia, India and Pakistan.

Other non-OECD regions

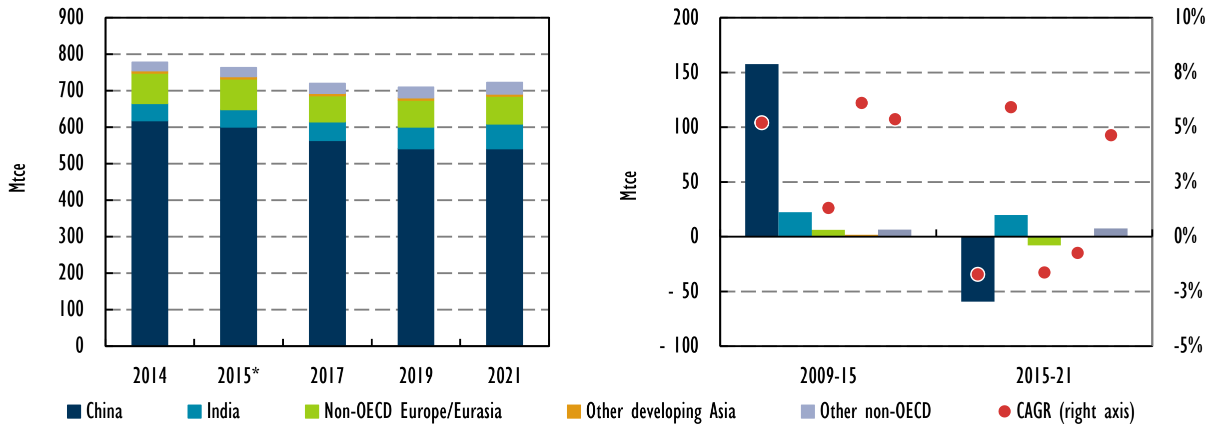
Thermal coal and lignite demand in Africa and the Middle East is expected to grow by 1.2% per year during the outlook period, increasing from 146 Mtce in 2015 to 156 Mtce in 2021. In Dubai, construction of a 2.4 GW coal power plant started in 2016. Egypt currently has two coal power plants with a total capacity of 6 GW at the advanced planning stage, and has announced plans to build another 12 GW of coal-fired capacity by 2022. Furthermore, since approval in 2014 of coal use in industry, many cement kilns have switched from gas to coal. In 2016, additional thermal coal licences were granted to cement producers, further increasing demand for thermal coal. In South Africa, a total capacity of 9.6 GW will be operational when construction of the Kusile and Medupi power plants is complete. After a substantial delay, the first unit of Medupi was commissioned in August 2015 and the remaining units are expected to be commissioned during the outlook period. The first unit of the Kusile plant is scheduled to start operation in July 2018, and the rest of the plant is expected to be operational by 2022. In October 2016, it was announced that the two successful bidders in the Coal-based Independent Power Producer Programme, the Khanyisa consortium and the Thabametsi consortium, will develop around 850 MW of coal-fired capacity. A 600 MW plant is planned to be commissioned in 2020 and the remaining capacity in 2021.

Thermal coal and lignite demand in Latin America is expected to grow an average 4.3% per year to reach 28 Mtce in 2021. Approximately 2.7 GW of coal-fired generation capacity is currently under construction, making power generation the major contributor to coal demand growth. Non-OECD Europe/Eurasia demand for thermal coal and lignite is similarly expected to grow 1.1% per year during the outlook period, increasing from 216 Mtce in 2015 to 230 Mtce in 2021.

Met coal

Met coal demand in OECD non-member economies is expected to decrease slightly, dropping from 763 Mtce in 2015 to 723 Mtce in 2021 at an annual average decline of 0.9% per year. Non-OECD demand will continue to account for about 80% of global met coal demand throughout the outlook period.

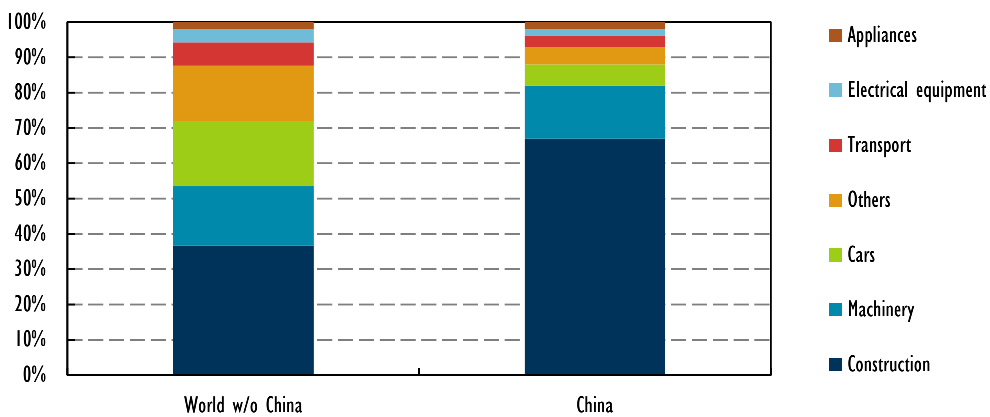
Figure 3.12 Forecast met coal demand for OECD non-member economies



* Estimate.

Chinese met coal demand will decrease by 1.7% per year on average during the outlook period, dropping from 601 Mtce in 2015 to 541 Mtce in 2021. Demand is expected to decrease particularly strongly up to 2019 and stay relatively flat from 2019 onwards. A very large portion of the total steel consumed in China is used in the construction sector (Figure 3.13). With restructuring of the Chinese economy, infrastructure development and construction projects will reduce pace considerably, causing a significant decline in Chinese steel demand and production.

Figure 3.13 Chinese steel consumption by sector compared with the rest of the world



Chinese steel exports are also expected to decline in the medium term as a result of sectoral restructuring and cost considerations. The share of scrap-based steel production is expected to increase, which also contributes to lower met coal demand. Steel consumption is, however, expected to eventually stabilise, hence the flat met coal demand forecast after 2019. Nevertheless, China's share in global met coal demand will drop from 63% in 2015 to 60% in 2021. Similarly, its share of non-OECD demand will drop from 79% to 75% during this period.

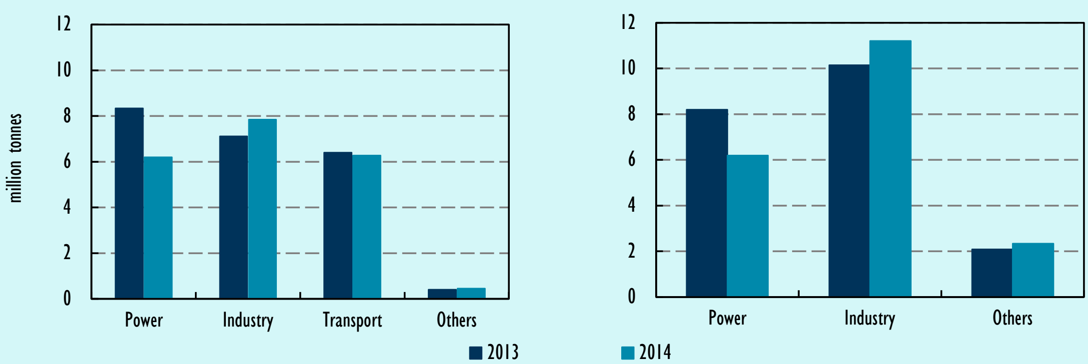
Demand for met coal in India is expected to grow significantly, at an average yearly rate of 5.9%, from 48 Mtce in 2015 to 68 Mtce in 2021. India is projected to become the second-largest steel producer over the forecast period, and almost the largest producer of BFI (reaching Japanese production levels). Consequently, India will have the largest absolute growth in met coal demand during the outlook period. Steel demand will be driven by strong economic growth and underpinned by a series of programmes announced by the government, such as the House for All initiative, Make in India, Dedicated Freight Corridor (DFC) construction, the 24x7 Power for All initiative, the Smart Cities programme, etc. – all very steel-intensive.

Non-OECD Europe/Eurasia demand for met coal will decrease annually by 1.6% on average, falling from 84 Mtce in 2015 to 76 Mtce in 2021. Non-OECD Europe/Eurasia nevertheless remains the second-largest met coal-consuming group after China during the outlook period. Met coal demand in Africa and the Middle East is expected to increase by 3.3% on average per year, to reach 7 Mtce in 2021. In Latin America, met coal consumption will similarly grow by 1% per year, totalling 16 Mtce in 2021. Demand in ASEAN countries will have the largest relative growth during the outlook period, increasing by 19% on average each year; thus, met coal demand in ASEAN countries will more than double to 8 Mtce in 2021. Demand in other developing Asian countries will remain roughly unchanged.

Box 3.4 Air pollution in China

Owing to public opinion, air pollution in Chinese cities continues to be a priority for political leaders. Efforts to improve air quality in China will shape coal demand – not only in terms of volumes, but also in how coal is used and the quality of the coal itself. Figure 3.14 shows that at the same time as power sector emissions decreased in 2014, industrial emissions rose (according to the most recent data available*), and current industrial emissions of both nitrogen oxide (NO_x) and sulphur dioxide (SO_2) are higher than for power generation. Regarding transportation, many older, high-polluting vehicles were retired recently, with the obvious environmental benefit of reduced NO_x emissions in the transport sector. For dust (fine particles and inhalable coarse particles), comparison between 2013 and 2014 is not representative, as the system for reporting and calculating has changed.

Figure 3.14 NO_x emissions (left) and SO_2 emissions (right) of various sectors in China

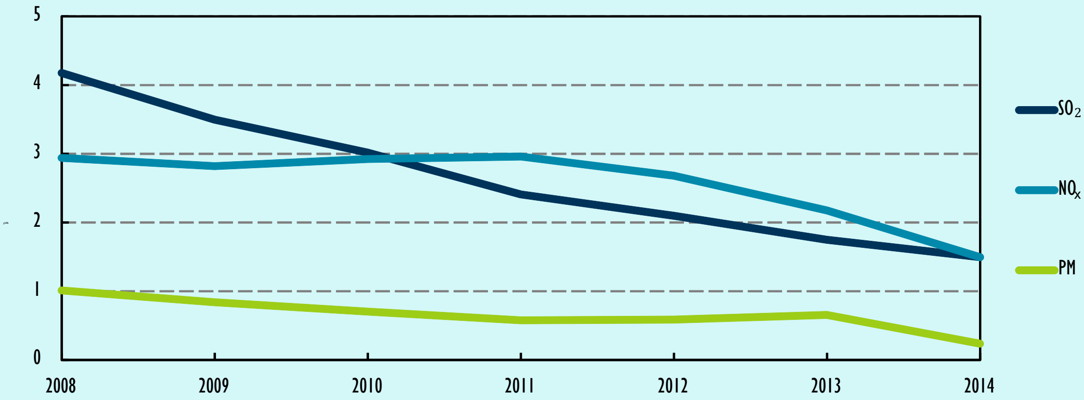


Specific emissions of sulphur and particulate matter from the power sector (in grammes per kilowatt hour [g/kWh]) continued the decline which started in 2006 (with a hiatus in declining particle emissions from 2011 to 2013), and NO_x emissions pursued the decline which began in 2011 (Figure 3.15). These emissions reductions were driven by the new, more stringent standards enforced by the government from 1 January 2012 for new plants; existing plants had to comply with the new standards by July 2014. As a result, power companies invested heavily in construction and retrofitting for desulphurisation, electrostatic precipitators (ESPs) and filters to remove particulate emissions, and denitrification. In an

Box 3.4 Air pollution in China (continued)

effort to improve air quality, even in plants complying with the standards, some power producers have implemented a so-called ultra-low emissions retrofit to reduce emissions to below the level of gas-fired power plants, at a very low increase to electricity costs (USD 1-2/MWh).

Figure 3.15 Emissions from coal-fired power plants in China



Note: PM = particulate matter.

Whereas retrofitting coal-fired power plants can be done with existing technologies at affordable costs, reducing emissions in the industrial sector poses a greater challenge – especially the small distributed boilers for industrial, commercial and residential use, of which there are half a million in China. In this case, substitution with gas, where available, electric boilers if suitable or combined heat and power (CHP) and coal quality control will be more practical means to improve air quality.

* Whereas the trends and sectoral comparison in this box are relevant, these data are not comparable with other data reported and treated with a different methodology.

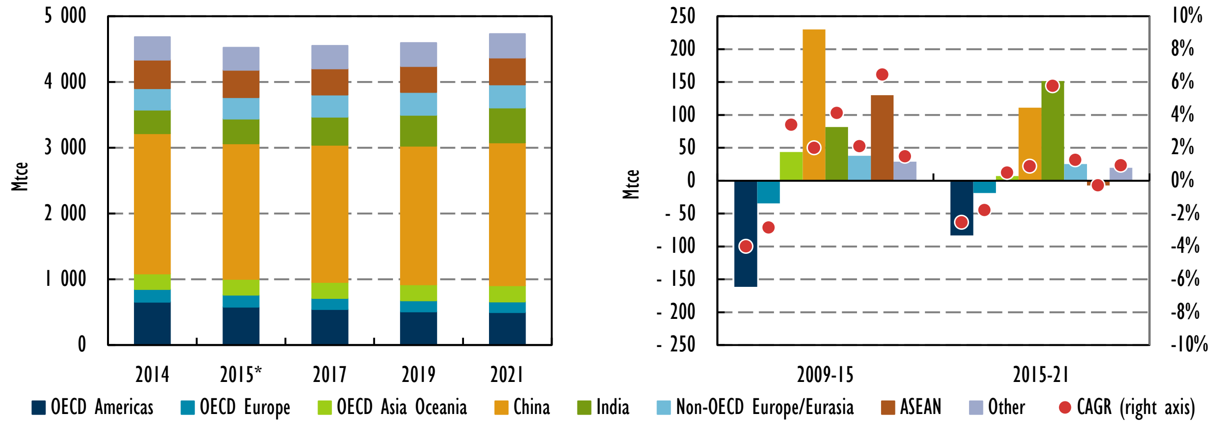
Global coal supply forecast

The global coal supply is projected to increase from 5 491 Mtce in 2015 to 5 636 Mtce in 2021, an average growth of 0.4% per year. OECD non-member economies are the drivers for growth, with an incremental increase of 241 Mtce in production. Despite growth in OECD Asia Oceania, overall OECD coal production decreases because of the significant decline in OECD Americas and OECD Europe.

Thermal coal and lignite supply forecast, 2016-21

The global supply of thermal coal and lignite is forecast to grow by 0.7% per year on average, increasing from 4 525 Mtce in 2015 to 4 728 Mtce in 2021. By 2021, thermal coal and lignite will account for 84% of total coal production. With an increase of 297 Mtce from 2015, OECD non-member economies are the main contributors to global growth in thermal coal and lignite production during the outlook period; in contrast, the OECD supply decreases by 95 Mtce. This significant drop in supply is mainly caused by a major decline in OECD Americas and, to a lesser extent, in OECD Europe. The increase in supply from OECD Asia Oceania (i.e. Australia) is not enough to offset these decreases.

Figure 3.16 Forecast thermal coal and lignite supply



* Estimate.

Thermal coal and lignite production in the United States is projected to decline significantly, by an average 2.7% per year during the outlook period. Hence, as production decreases from 550 Mtce in 2015 to 468 Mtce in 2021, the United States will cease to be the second-largest producing country and will fall behind India to become the new third-largest producer. Decreasing domestic demand as a result of less costly natural gas and stricter environmental regulations are the primary factors contributing to this decline. Another is the decreased competitiveness of thermal coal from the United States: high mining costs in the Appalachian Region and high transportation costs in the Western Region, in addition to a relatively strong currency, made US thermal coal less competitive in international markets. Cost-cutting measures in the United States have largely reached their limits, witnessed by an increasing number of higher-cost mines being left to idle in 2015 due to low coal prices. A significant number of mining companies declared bankruptcy recently as a result: Peabody Energy filed for bankruptcy in April 2016 for most of its US operations excluding activities in Australia, and joining other companies such as Alpha Natural Resources, Arch Coal, Patriot Coal and Walter Energy in bankruptcy protection. Looking forward, a slimmer, more competitive coal industry will emerge in the United States, but it will struggle to survive in a shrinking market, with coal prices kept in check by abundant gas production and low gas prices.

After deep restructuring of the coal sector in Poland, better management, improved use of human resources and assets, and more productive investments should lead to a reduction in production costs. Productivity in the sector grew 7%, increasing from 706 t per worker in 2014 to 756 t in 2015. This partially explains the 20% production cost reduction, from an average of PLN 318/t in 2014 to PLN 257/t in 2015. The *MTCMR 2015* assumed the closure of Brzeszcze, Makoszowy, Bobrek and Piekary coal mines during the period; however, the acquisition of these mines by Tauron (Brzeszcze), SRK (Makoszowy) and Weglowoks (Bobrek and Piekary) – three state-owned companies committed to making the mines profitable – makes stability rather than decline probable in Polish coal production.

China remains the largest producer of thermal coal and lignite, with production forecast to grow slightly, by 0.9% per year on average during the outlook period. Total Chinese production in 2021 is thus expected to be 2 171 Mtce in 2021 – up by 111 Mtce from the 2015 amount of 2 060 Mtce. By 2021, 46% of global thermal coal and lignite output is produced in China. The Chinese government is determined to reduce excess mining capacity to resolve the problem of oversupply: for this reason, it reduced the annual number of working days of miners from 330 to 276 and announced that it will stop approving new coal mine projects for the next three years starting in 2016. The NEA additionally plans to close more than 1 000 coal mines in 2016. However, because of a strong surge in prices, China relaxed measures concerning production cuts for various mines in September 2016. Chinese production is therefore expected to decrease in the short term, but increase again in the mid-term as the measures are gradually loosened once the market is more balanced. It will be necessary in the future to closely monitor National Development and Reform Commission (NDRC) policies, which can change as prices evolve and will determine Chinese production levels.

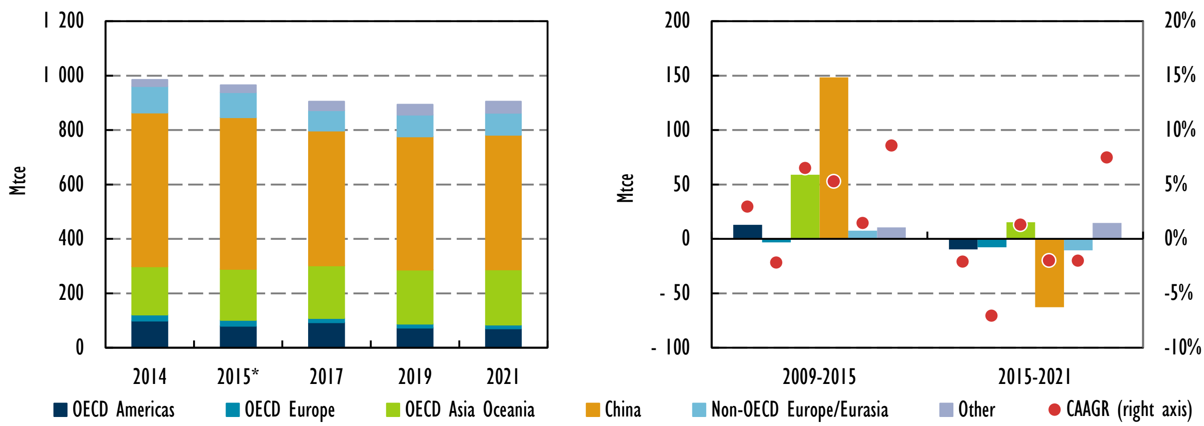
Indian thermal coal and lignite production will grow the most during the outlook period, increasing by 5.8% each year on average, from 379 Mtce in 2015 to 530 Mtce in 2021. In 2016, the state-controlled coal mining company Coal India Limited (CIL) achieved a record output, and the government aims for higher output levels in coming years to reduce the amount of coal imported. Twenty to 25 new mines are planned to become operational by 2020, and improved technologies and efficiency and productivity measures for mining are expected to be implemented. In 2016, 17 blocks were allocated to state-owned mining companies, which are expected to start production in the coming years. This is another indication of the strong ambition of the Indian government to ramp up domestic coal production.

Production of thermal coal and lignite in ASEAN countries is projected to decrease from 415 Mtce in 2015 to 408 Mtce in 2021, an average annual decline of 0.3%. The major contributor to this decline in the short term is Indonesia, where production cuts are expected. Production in Africa and the Middle East will grow by 0.6% per year on average, and growth of 2.4% per year is expected in Latin America, owing mainly to increased production in Colombia. Non-OECD Europe/Eurasia output grows similarly by 1.3% per year during the outlook period.

Met coal supply forecast, 2016-21

Global met coal production is forecast to decline 1% each year on average, dropping from 966 Mtce in 2015 to 908 Mtce in 2021. Production in OECD non-member economies will decrease from 676 Mtce to 620 Mtce at an average annual rate of 1.4%. The share of non-OECD production in global output will consequently decrease from 70% to 68% during the period.

Figure 3.17 Forecast met coal supply



* Estimate.

In OECD Americas, met coal production will decrease 2.1% per year, falling from 80 Mtce in 2015 to 71 Mtce in 2021. Despite a restricted supply of high-volatile US coking coal, mines that were closed recently because of low prices are not expected to reopen, and new investments are difficult to finance. Similarly, the met coal supply in Europe is expected to decline a significant 7.1% per year, dropping from 22 Mtce to 14 Mtce during the period. Germany will lead this trend to 2018, when all coking coal production will cease. Output in OECD Asia Oceania, on the contrary, will increase from 187 Mtce to 202 Mtce at an average annual growth rate of 1.3%, led by Australia.

China will remain the largest met coal producer; met coal output in China is nevertheless expected to decrease from 558 Mtce in 2015 to 495 Mtce in 2021, an average decline of 2% per year. As met coal production in China mainly supplies domestic consumption, the ongoing restructuring of the Chinese economy and the resulting slowdown in the steel sector are the main reasons for the decline in production.

Met coal production in ASEAN countries and other developing Asian economies is expected to grow minimally during the outlook period, driven by Indonesia as well as Mongolia, which is expected to recover the production lost in recent years of low prices, although this will depend on exports to China. Met coal production in non-OECD Europe/Eurasia will decline by 2% on average per year, to 81 Mtce in 2021, with great uncertainty in Ukraine. Colombian and Indian met coal output will increase slightly.[20] Regarding Africa, new prospects have appeared in Mozambique after the coking coal price rise in 2016. In addition to the small producers which could restart operations, in September 2016, Vale and Mitsui reached new terms for agreement to boost their project in Moatize. Mitsui will provide USD 450 million, subject to certain conditions, to buy a 15% share of the Moatize mine and USD 350 million to buy 50% of the Nacala Corridor. This new agreement shows the commitment of both companies to ramp up output in Mozambique. Washing capacity is being doubled and the target of 22 million tonnes per annum (Mtpa) is unchanged. But the increase in Mozambique output, around 4 Mt by 2021, is partially offset by a slight decrease in South Africa.

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[20] Met coal statistics from India are usually difficult to interpret. Some coals classified as coking coal are actually used in steam and heat production since they are not suitable for coke production due to quality issues.

4. MEDIUM-TERM FORECAST OF SEABORNE COAL TRADE

Key findings

- **Seaborne coal trade in 2021 will be near the 2014 level after falling for a time and then recovering. The shift to the Pacific Basin is projected to continue.** Total seaborne trade volume will increase from 1 021 million tonnes of coal-equivalent (Mtce) in 2015 to 1 079 Mtce in 2021. Thermal coal trade is expected to account for slightly more than half of the incremental growth in trade.

- **Chinese imports are expected to decline, but not without significant uncertainty.** Total coal imports by the People's Republic of China (hereafter "China") are projected to decline by 2.9% per year on average, to 150 Mtce in 2021. Despite 2016 temporary increase, policy changes in China could drastically affect coal imports.

- **Indian imports are expected to increase over the outlook period.** With domestic production increases being limited at the same time as demand grows, total coal imports in India are expected to grow by 3% each year on average, to reach 205 Mtce by 2021. There is, however, uncertainty on how production in India will evolve.

- **Japanese and Korean coal imports are forecast to stabilise.** Despite new coal-fired capacity in Japan, increasing power generation from renewables as well as sluggish power demand will result in Japanese imports remaining relatively flat. In Korea, the competitiveness of coal is expected to decrease owing to a higher carbon tax and lower liquefied natural gas (LNG) prices.

- **European imports will decrease.** Despite an expected decline in production, a stronger decrease in demand will reduce total coal imports into Europe by almost 6% each year over the outlook period.

- **Australia will remain the largest exporter of coal, and the gap between Australia and Indonesia will widen.** Indonesian exports will be reduced largely by growing domestic demand and structural problems within the country. Australia, however, will remain a highly competitive exporter.

- **Coal imports by Viet Nam, the Philippines, Malaysia and Pakistan will increase.** Over the outlook period, a total of almost 25 gigawatts (GW) of additional coal-fired generation capacity is expected to come on line in these countries. Although the four countries have some coal reserves, the bulk of the additional coal needed will come from imports.

Methodology and assumptions

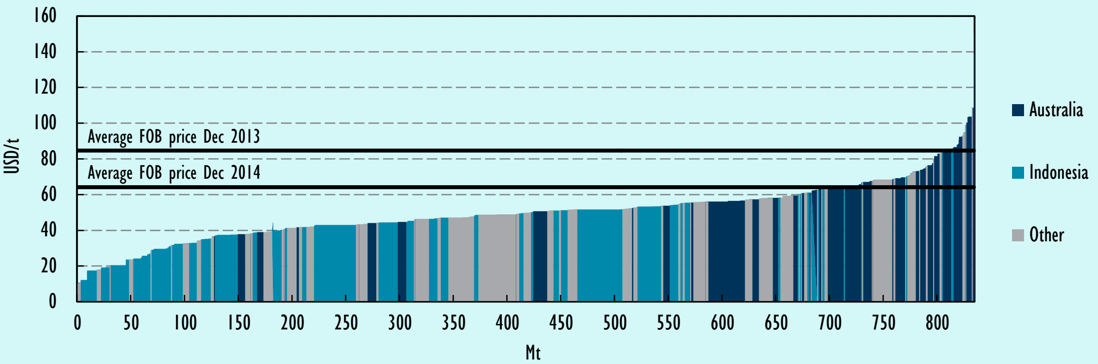
This chapter provides a medium-term forecast for international thermal and metallurgical (met) coal trade, based on spatial equilibrium models.[21] Using these models, trade flows between exporting and importing countries up to 2021 are estimated. The assumptions used in the models include the future development of coal demand, transport costs, production costs, mining capacities and infrastructure capacities.

Major coal mining regions and demand hubs are included in the simulation models. The models also feature detailed datasets on mining and transport costs, as well as capacities for ports, railways and mines. Detailed lists for mine and infrastructure capacity expansions are used, and variations in coal qualities are taken into account by type (thermal or met) and by energy content. Mining cost development is estimated based on assumed prices for input factors such as diesel fuel, steel products and labour. Owing to escalating input prices and deteriorating geological conditions, productivity gains are assumed to be below increases in infrastructure and mining costs. The main policies relating to coal export quotas, taxes and royalties, are assumed to stay constant during the outlook period unless changes have been firmly committed.

Box 4.1 Models: Evolving with the market

Econometric models are a vital tool to analyse energy markets, as they build a simplified theoretical representation of markets and their functioning based on mathematical expressions. Once formulated, models can be tested empirically with historical data and can then be used to forecast market developments based on various basic assumptions in a consistent framework. Consequently, model results are widely used to quantitatively assess the effects of policy decisions on market outcomes. But models need to be adapted to real market conditions, which change quite often. The following examples showing market outcomes for international seaborne coal trade would not be correct had the models not been properly updated.

Figure 4.1 Indicative thermal coal FOB cost curve and FOB prices, 2014



Notes: FOB = free-on-board; t = tonne; Mt = million tonnes.
Sources: Adapted from Wood MacKenzie (2015), *Coal* (private database), accessed April 2015; McCloskey (2015), *McCloskey Coal Reports 2010-2015*, http://cr.mccloskeycoal.com.

[21] For more details, see previous editions of this report. A detailed description of the thermal coal trade model can be found in Paulus and Trüby (2011). For further details on the met coal trade model, please refer to Trüby (2013) or Trüby and Paulus (2012).

Box 4.1 Models: Evolving with the market (continued)

Figure 4.1 shows the international seaborne market supply curve for thermal coal in 2014, as well as the price development for thermal coal in 2014. Based on these cost data, which are typically used in a similar form in coal market trade models, it is expected that the expensive producers at the top of the supply curve (located mainly in Australia) will be crowded out of the market. However, the actual changes in trade flows in 2014 show that the real-world developments are not in line with the model's prediction, mainly because Indonesian exporters significantly reduced their export volumes. Although Indonesian producers are located in the mid- to low-cost area of the supply curve, it is the Australian companies that increased their exports in 2014.

In reality, coal is not a homogenous product, and quality differentials in terms of energy, ash, sulphur and volatile content are significant. Although coal blending and boiler flexibility make it difficult to assign one type of coal to one destination, a proper modelling can easily adjust for this problem. In addition, many of the Australian producers have take-or-pay contracts with rails and ports; these costs are therefore not variable, but sunk costs. This also has to be taken into account in modelling, which is difficult as these data are not easy to obtain. This example therefore illustrates the complications involved in adapting models to real life.

Another example of complex coal market interactions is the shipping of Colombian coal to South Korea, which is not competitive at current spot prices of coal and freights. This situation is the result of South Korean power producers using long-term chartered vessels that are contracted at freight rates much higher than the current rates. Given that a round trip from Australia to Korea is 40 days while the trip to Colombia is 120 days, sending the contracted capacity to Colombia and going to the spot market for two shipments to Australia may be less costly than using the whole contracted capacity to bring three shipments from Australia, if the price differential between Colombian and Australian coal falls within in certain range. This happened in 2016.

These two cases show that, to capture real-world complexity, econometric models need to be updated and calibrated as conditions evolve, and the limitations of the models need to be taken into account when results are interpreted.

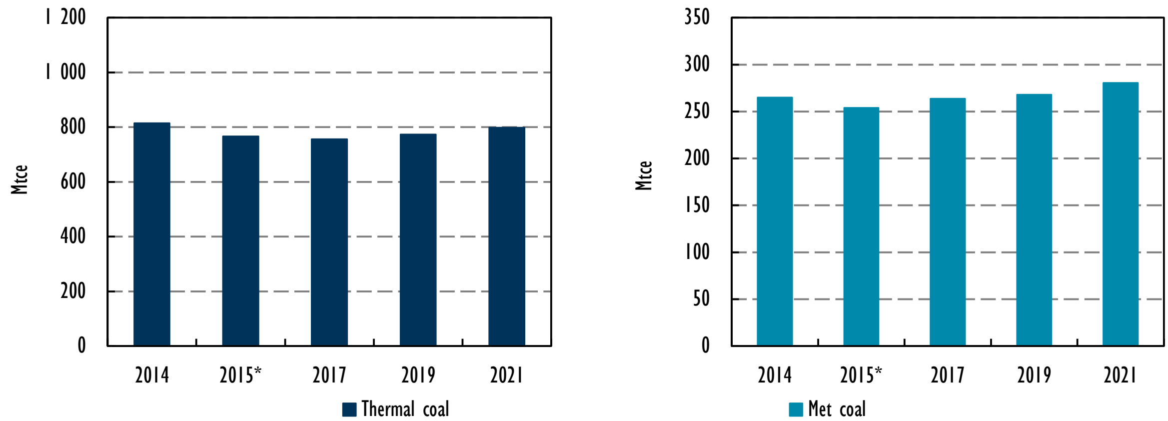
Seaborne coal trade forecast

During the outlook period, seaborne hard coal trade is forecast to grow by 0.9% on average per year, from 1 021 Mtce in 2015 to 1 079 Mtce in 2021, despite an initial decline. With annual average growth of 0.7% and an absolute increase of 31 Mtce, thermal coal trade accounts for 54% of the incremental growth in total trade. Met coal trade is forecast to increase by 27 Mtce during the period, at an average annual growth rate of 1.7%.

Organisation for Economic Co-operation and Development (OECD) net imports of hard coal are expected to decrease very sharply, from 86 Mtce in 2015 to 8 Mtce in 2021 – a staggering fall of 32.7% per year on average. This is owing to a substantial decline in imports into OECD Europe, as well as declining US exports. Australia remains the largest hard coal exporter in the world in terms of both energy content and mass over the outlook period.

Among OECD non-member economies, net imports of hard coal by China are projected to decrease significantly. In contrast, Indian net imports of hard coal will grow strongly, and India will surpass China to become the world's largest coal importer again. The Association of Southeast Asian Nations (ASEAN) group of countries will continue to be a net exporter, mainly owing to considerable Indonesian exports. However, net exports will decline substantially because of increasing domestic consumption. Net exports from Latin America will grow slightly during the forecast period as a result of Colombian exports, and non-OECD Europe/Eurasia net exports will similarly grow marginally. Figure 4.2 illustrates total seaborne thermal and met coal export development over the outlook period.

Figure 4.2 Forecast total export volumes in international seaborne steam coal (left) and met coal (right)

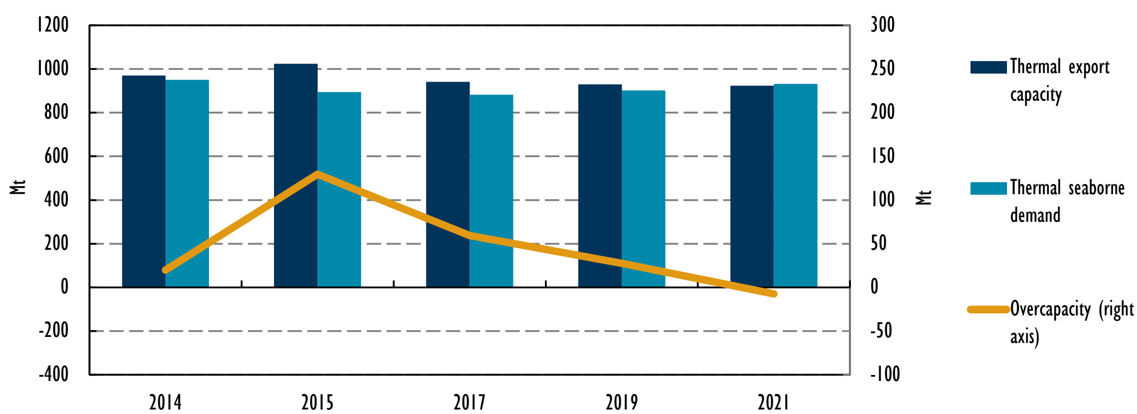


* Estimate.

Seaborne thermal coal trade forecast, 2016-21

Seaborne thermal coal trade, after a brief decline resulting mainly from the initial sharp decrease in European imports, is expected to increase from 2017 onwards, surpassing the 2015 volume of 767 Mtce to reach 798 Mtce by 2021 – an annual average growth of 0.7%. The decline in European imports is more than offset by increased imports in the ASEAN and other developing Asian countries. During the outlook period, seaborne thermal coal will continue to account for about 18% of global thermal coal consumption. Figure 4.3 illustrates the overcapacity in recent years in the seaborne thermal coal market, especially in 2015. It is expected that thermal coal export capacity will decline throughout the outlook period, to eventually reach a balance with thermal seaborne demand in 2021. However, price hikes in 2016 proved that real overcapacity is lower than illustrated. In other words, actual capacity is lower than nameplate capacity, mainly owing to logistical issues and weather disruptions in major exporting countries.

Figure 4.3 Seaborne thermal coal demand and indicative development of thermal export capacity



Thermal coal imports by India are projected to increase from 123 Mtce in 2015 to 142 Mtce in 2021, by an average of 2.4% per year. India will thus surpass China to become the largest importer. Despite the expected increase in domestic production, imports will rise significantly during the outlook period.

The Indian government has set an ambitious goal to produce 1 500 Mt of coal by 2020, 1 000 Mt of it by state-run Coal India Limited (CIL). For this purpose, procedures for land acquisition and mining approvals have been accelerated, and infrastructure improvements are planned. In August 2016, railway freight rates for distances between 200 kilometres (km) and 700 km were raised by 8% to 14%, whereas for over 700 km they were lowered by 4% to 13%. While this decision raises costs for numerous coal-fired power plants, it will make domestic thermal coal more competitive with lower-priced imports for plants located in the coastal regions far from the mines. However, it is expected that the effects of these measures will be limited over the outlook period and India will continue to be strongly dependent on imports. There are three reasons supporting such statement. The first is quality: some coastal plants were designed to burn lower ash coal than the domestic standards, and hence, domestic coal will not replace imported coal. The second is the regulation of pollution, which encourages the use of lower ash imported coal, either directly or blended with domestic coal. The third is economic since transportation costs to consuming centres in some locations are significant.

Chinese thermal coal imports are forecast to decrease from 121 Mtce in 2015 to 104 Mtce in 2021, declining by 2.6% per year on average. Various factors contribute to this decline: first, demand in China is expected to remain relatively flat with rebalancing of the economy; this will result in more demand being covered by domestic production. Second, consumption of coal in China is moving away from coastal regions towards the interior where the mines are located because of environmental regulations for cities and the availability of new transmission lines. Domestic coal is therefore becoming more competitive because of decreased transport distances from the mines to the consumption regions. Finally, measures such as quality control requirements and the import tax on thermal coal are further expected to increase the competitiveness of domestic coal.

Figure 4.4 Chinese coal imports compared with direct and indirect coal exports

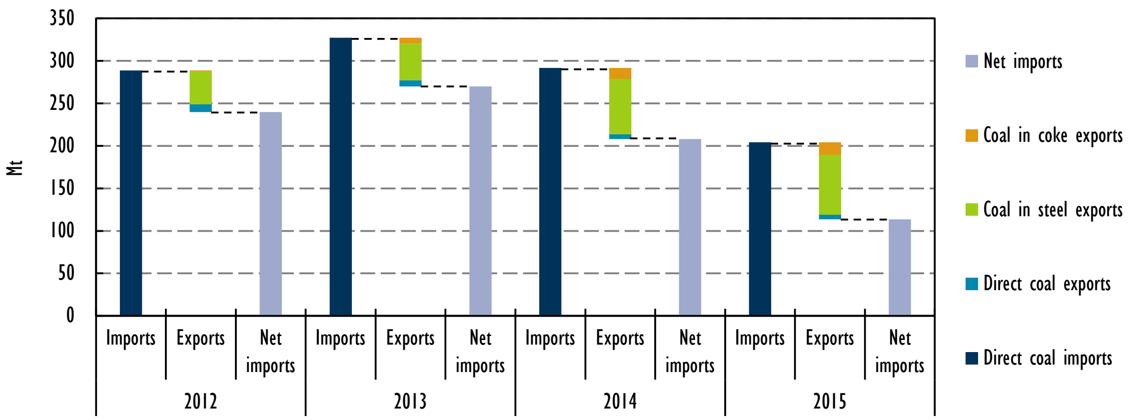


Figure 4.4, which compares Chinese coal imports with direct and indirect coal exports, demonstrates that a significant portion of imported coal is exported back in the form of products such as coke and steel. Because of declining coal imports and significant growth in coke and steel exports, the share of coal exported indirectly back has risen sharply in recent years. In 2015, China exported just slightly less than half of the coal it had imported back into the market as steel and coke.

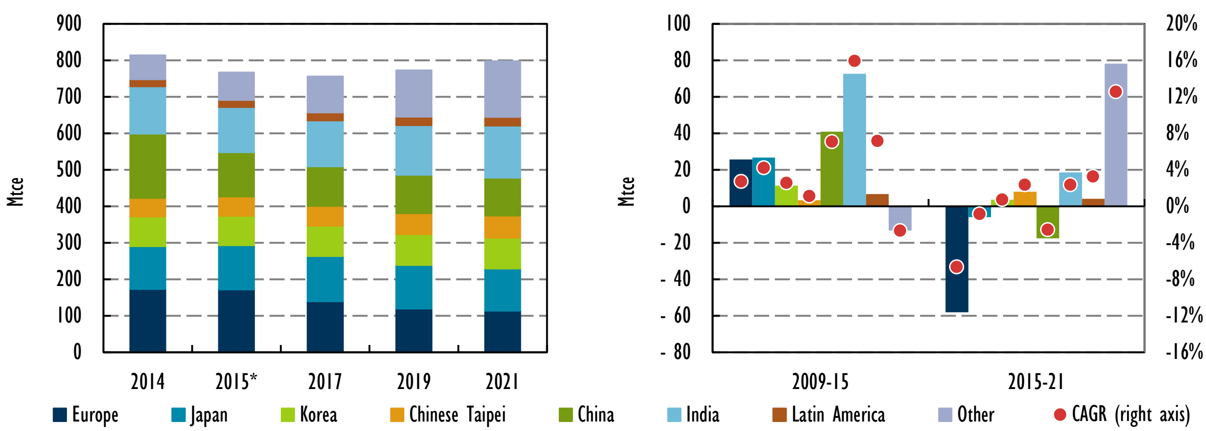
The production cuts and higher prices that occurred in China in 2016 could potentially trigger an increase in less expensive imports owing to the arbitrage effect. However, the increase in imports will likely be a short-term phenomenon, and with the softening of other measures in the medium term, Chinese imports are expected to continue declining during the outlook period.

In Europe, thermal coal imports will decline significantly by an average 6.6% each year as a result of decreased demand, falling from 172 Mtce in 2015 to 114 Mtce in 2021. However, the decrease in domestic production in Germany and the United Kingdom, as well as increased imports by Turkey, will slightly hinder the overall decline in European imports. As Turkey has very limited domestic steam coal production, it is strongly dependent on imports for its power plants that consume hard coal. Turkish thermal coal imports are expected to increase as additional coal-fired generation comes on line during the outlook period.

In Poland, the strong commitment of the government to maintain production in the Brzeszcze, Makoszowy and Bobrek-Piekary mines raises projected values for coal production in 2021. At the same time, more renewable energy and additional natural gas generation keep coal demand quite stable in Poland during the outlook period, translating into stabilisation in imports as well.

Japanese thermal coal imports are expected to decrease by 0.8% per year on average following a slight decline in demand, to drop from 121 Mtce in 2015 to 115 Mtce in 2021. Imports by Korea will increase slightly, by 0.7% per year, rising from 81 Mtce to 85 Mtce during the same period. The main reason for this limited growth – despite an increasing number of coal-fired plants – is the declining competitiveness of coal in Korea because of lower-priced LNG and high carbon taxes. Additionally, Korea raised its coal import tax in July 2015, which particularly affects lower-calorific-value coals such as those from Indonesia. Chinese Taipei is also expected to import increasing amounts of thermal coal throughout the outlook period to supply growing coal-fired generation: imports will increase from 53 Mtce in 2015 to 61 Mtce in 2021.

Figure 4.5 Forecast seaborne thermal coal imports



* Estimate.

Total thermal coal imports in Southeast Asian countries are projected to increase about 73 Mtce over the outlook period. Imports into Malaysia, Thailand, Viet Nam and the Philippines will grow particularly strongly as a result of large coal-fired generation capacities being commissioned. Although these four countries have coal reserves (in Malaysia only on the island of Borneo), the new plants will consume mostly imported coal. In Figure 4.5, which depicts the development of seaborne thermal coal imports over the outlook period, these countries are covered in the "Other" category, together with the United States and several small importers. In Viet Nam, expansion of the Duyen Hai coal terminal is to be completed by 2020: the port is expected to have an export capacity of 40 million tonnes per annum (Mtpa) and be able to serve vessels of up to 160 000 deadweight tonnage (dwt).

Other countries in the area, Pakistan in particular, are also relying on imported coal for developing new generation, although the government wants to limit coal imports growth. A special case is Bangladesh, where the proposed capacity is massive (on the order of 20 GW), a large share of which is served by imported coal. However, given the slow progress none of this capacity is assumed to be on line in the outlook period.

Thermal coal imports into Africa and the Middle East are expected to have considerably limited growth over the outlook period, with a projected increase of only 3 Mtce. While growth in the cement industry and imports to power plants in Morocco and in the United Arab Emirates will support coal imports, many of the coal-fired power plants announced in the region elsewhere are not expected to become operational during the forecast period. The most interesting case is Egypt, where the government is trying to end the electricity shortage and outages. Its strategy relies on gas, renewables and nuclear energy, but also on new coal-fired power plants, which are to meet a growing share of the electricity demand. So far, over 15 GW of new coal capacity have been announced. If all these imported coal-based projects are built, imports to Egypt could reach 50 Mtpa. The most advanced project is a 2 640 megawatt (MW) plant in the Oyoun Mossa area, developed by Al Nowais, a company from the Emirates. The government's target is to have the first unit connected to the grid by 2020; however, given the complexity of the projects and delays in securing financing, none of the plants is assumed to come on line during the outlook period. In the case that any of these plants make significant progress in the coming years, the forecast will be updated accordingly.

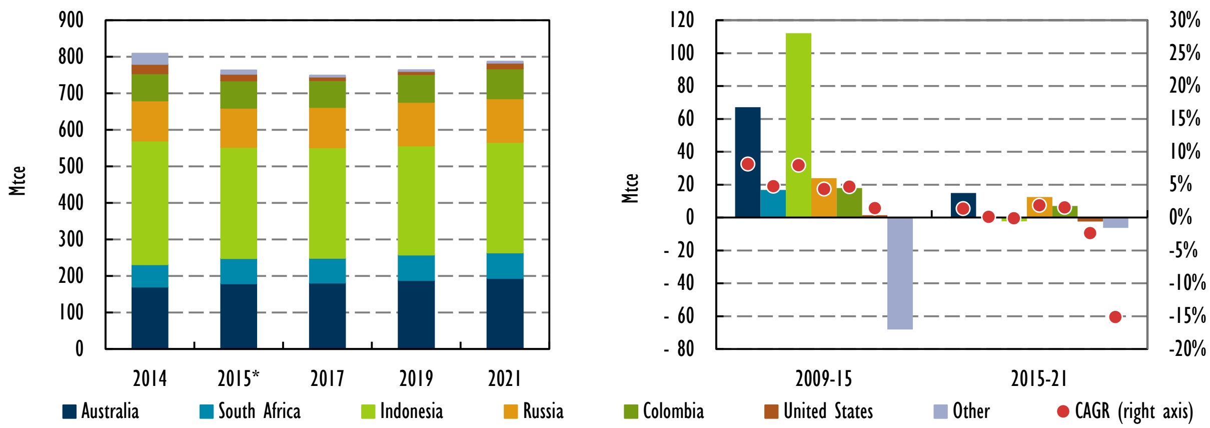
Among major thermal coal exporters, Indonesia will continue to have the largest volumes of thermal coal exports over the outlook period, despite its share in the global seaborne market decreasing from 42% to 38%. Thermal coal exports of Indonesia will be 302 Mtce in 2021, roughly unchanged from 304 Mtce in 2015. The relatively flat trajectory of exports results from the combination of several factors: first, additional demand from new coal-fired power plants will increase domestic consumption, resulting in decreased exports. Furthermore, the expected slowdown in growth of Chinese and Indian imports, combined with competition from Australian and South African coal, will continue to put pressure on Indonesian exports. Strong demand growth in countries such as Malaysia, Thailand, Viet Nam and the Philippines will drive exports, although the Indonesian government recently banned Indonesian-flagged vessels from sailing for the Philippines after the hostage-taking incident in June 2016, which was the third such case of the year.

Thermal coal exports from Australia will grow the most in absolute terms (+15 Mtce), rising from 179 Mtce in 2015 to 194 Mtce in 2021 at an average growth rate of 1.3% per year. As a result, Australia's market share in total seaborne thermal coal will increase slightly over the outlook period. Strong growth in Southeast Asia and other developing countries will be the main catalyst for increased Australian thermal coal exports, but exports to India, China and Korea could also contribute. Successful cost-cutting measures carried out in recent years by Australian producers will contribute to the competitiveness of Australian exports; however, several mines closed in 2015 due to low prices, reducing Australian export mining capacity. This situation could be reversed by the reopening of some of the mines if coal prices remain at current levels.

Russian exports are projected to grow by 1.9% per year on average, increasing from 107 Mtce in 2015 to 120 Mtce in 2021. Russia is traditionally a higher-cost supplier owing to the high transportation costs involved in its export coal production – a consequence of the large distances between coal mines and the Russian export ports. As demand for thermal coal in Europe declines and competition in Europe from Colombian and US coal increases, Russian exports are expected to shift more towards Asian countries which have a growing demand for thermal coal.

Because of its low production costs and high-quality thermal coal, Colombia's exports are forecast to grow at an average annual rate of 1.5%, increasing from 75 Mtce in 2015 to 82 Mtce in 2021. Despite declining demand, Europe will remain a major export destination for Colombian thermal coal. Another important export destination will be Latin America.

Figure 4.6 Forecast seaborne thermal coal exports



* Estimate.

South African thermal coal exports are projected to remain relatively flat during the outlook period, at around 69 Mtce. As thermal coal demand in the Atlantic Basin is expected to decrease, the major export destinations for South African shipments will be India and other developing Asian countries. Competition from Indonesia in the Asian markets, especially in India, will continue to put pressure on South African exports to Asia throughout the forecast period.

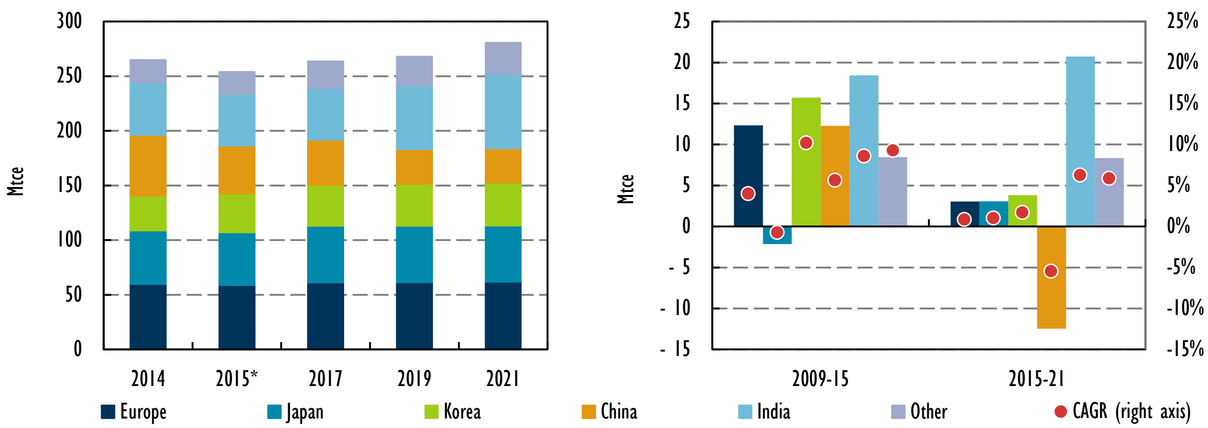
Thermal coal exports from the United States are forecast to decrease initially, from 18 Mtce in 2015 to as low as 8 Mtce in 2019, and then rise again to 16 Mtce in 2021. US mining costs are generally among the highest of all exporting countries, and are therefore at the upper end of the supply curve. But the strong decline in domestic consumption of thermal coal in the United States will make a large amount of coal available for the export market, which will eventually go to the seaborne market if thermal coal trade increases.

In August 2016, the Turkish government implemented a new tax on coal imports (USD 15/t)[22], which does not apply to Poland as a member of the European Union. The tax was updated in October. This tax exemption for Poland could incentivise Polish coal exports to Turkey, especially in an environment of low international prices, although coal used outside the power sector – a good market for Polish coal – could rebate the tax. This policy development, as well as good prospects in view for the export-oriented Jan Karski mine, could improve the competitiveness of Polish coal for export. Nevertheless, a great rise in Polish exports during the outlook period is not expected, given the production costs of existing mines and the supply needed to meet domestic market demands.

Seaborne met coal trade forecast, 2016-21

During the outlook period, seaborne met coal trade is projected to grow an average 1.7% per year, increasing from 254 Mtce in 2015 to 281 Mtce in 2021. Imports to the Atlantic Basin will largely stagnate, so growth will be driven primarily by India and other developing Asian countries. The share of seaborne met coal in global met coal consumption will increase from 27% to 31% during the period.

Figure 4.7 Forecast seaborne met coal imports



* Estimate.

Chinese met coal imports decline significantly over the outlook period, decreasing from 44 Mtce in 2015 to 31 Mtce in 2021. The strong decline in met coal demand in China, resulting from lower steel production, is the main reason for the decrease in imports. In 2015, imports from Mongolia accounted for almost one-third of total met coal imported by China. However, Mongolian met coal exporters suffered serious losses in 2015 due to low met coal prices. China is expected to continue importing a significant amount of coal from neighbouring Mongolia over the outlook period; nevertheless, with Chinese demand declining, Mongolian exporters will need to find other markets in the long term should they want to increase exports.

Met coal imports by India are expected to grow the most over the forecast period, increasing from 47 Mtce in 2015 to 68 Mtce in 2021 – a substantial annual average growth of 6.3%. The growing Indian economy, and a lack of significant coking coal reserves with the required quality, makes increasing imports a necessity. Australia will continue to provide the largest portion of Indian met coal imports during the outlook period.

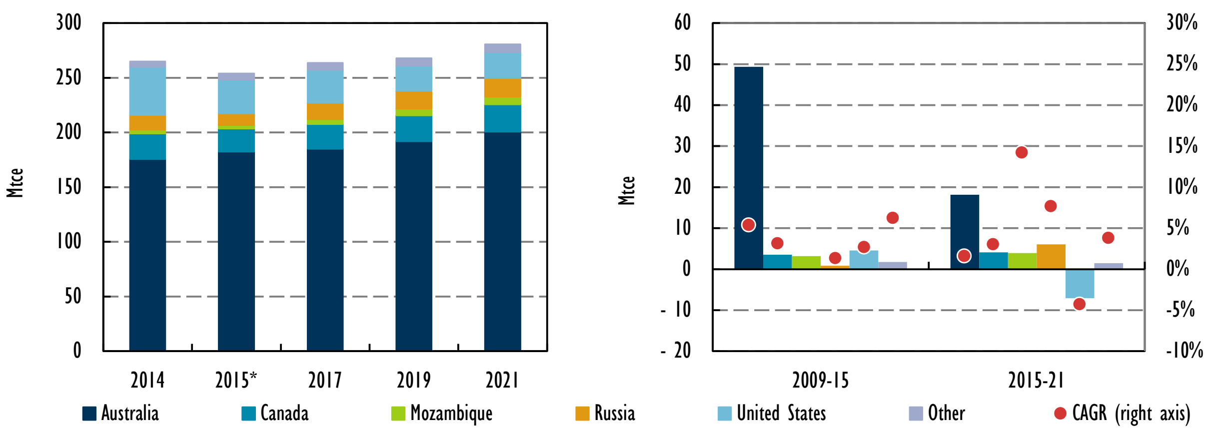
[22] The tax was changed as the difference between 70 and API2 (in $/t). Given that API2 has been over $70/t since this change, the tax has been ineffective so far.

Japan and Korea lack domestic met coal reserves, and therefore depend completely on imports to meet their met coal demand. In both countries, growth in met coal demand is strongly correlated with growth in the steel sector as well as economic growth. Japanese imports are expected to grow only slightly because of low gross domestic product (GDP) growth, increasing from 48 Mtce in 2015 to 51 Mtce in 2021. Korea will increase its imports during the same period from 36 Mtce to 39 Mtce – relatively higher growth, corresponding with greater GDP growth.

In Europe, met coal imports are projected to rise to 62 Mtce in 2021 from 59 Mtce in 2015, growing by a slight 0.8% per year on average. Overall growth occurs as a result of met coal demand increasing in growing economies such as Turkey at the same time as domestic met coal production in Europe falls.

Seaborne met coal supply is highly concentrated, with only a small number of countries providing most of the global supply. For instance, Australia alone accounted for 72% of global seaborne met coal exports in 2015. The three largest producer countries – Australia, the United States and Canada – supply 92% of global seaborne met coal. This share is projected to decrease to 89% by 2021, but even so, having most of the supply concentrated among such a small number of suppliers means the met coal market will continue to be vulnerable to supply disruptions resulting from weather conditions or labour strikes.

Figure 4.8 Forecast seaborne met coal exports



* Estimate.

Australian met coal exports are expected to grow by 1.6% per year, totalling 201 Mtce in 2021. This is an 18 Mtce increase from 2015, making Australia the exporter with the largest absolute growth over the forecast period.

US met coal exports will drop significantly, from 31 Mtce in 2015 to 24 Mtce in 2021 – an annual average decline of 4.3%. Met coal in the United States is produced in the Appalachian Basin, where costs are typically high; hence, when lower-cost producers in places such as Mozambique and Australia ramp up production, US met coal capacities are among the first to go off the market. One strong sales advantage, however, is that US high-volatile coking coal is excellent for blending. European and Latin American markets will continue to be the primary export destinations for US met coal.

Met coal exports from Canada are forecast to increase by 3% each year during the outlook period, to 25 Mtce in 2021; the Pacific Basin will continue to be the primary destination for Canadian exports. Russia will increase its met coal exports significantly, from 11 Mtce in 2015 to 17 Mtce in 2021, a substantial relative increase of 7.7% per year. Export growth will be supported by ambitious infrastructure investments and development of the eastern coal deposits in Russia.

The largest relative growth in met coal exports during the outlook period will be in Mozambique. Growing by 14% per year on average, met coal exports from Mozambique are expected to increase from 3 Mtce in 2015 to 7 Mtce in 2021. Vale, now in a joint venture with Mitsui, will continue to be the main producer in the country.

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5. EXPORT CAPACITY INVESTMENT OUTLOOK

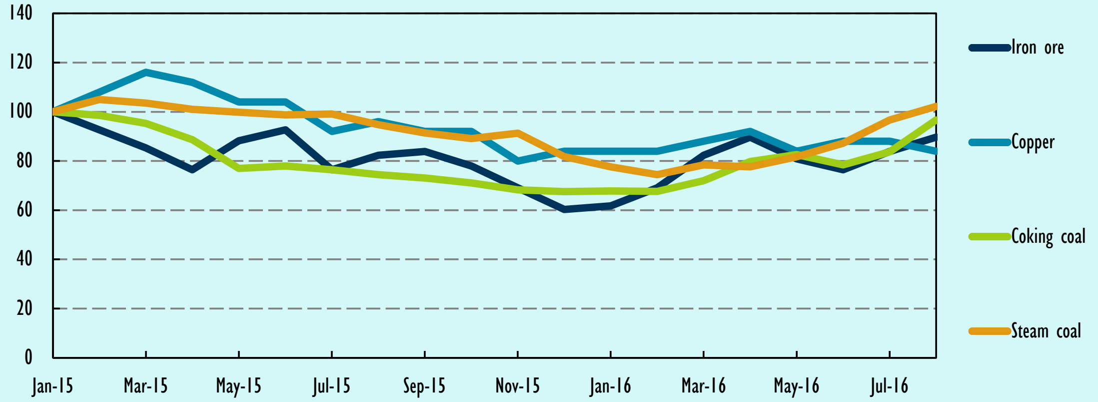
Key findings

- **Coal mining project capacity increased compared with last year's report. However, this does not mean that investments are growing.** On the contrary, it is only the result of a very limited number of projects realised in recent years, with the majority postponed. As the outlook period moves ahead, expansion projects have increased as a result.
- **The total capacity of more advanced export mining projects amounts to 100 million tonnes per annum (Mtpa).** Australia and Russia each accounts for 30% of the proposed projects, followed by Colombia at 20%. Mozambique (11%) also accounts for a significant share of more advanced projects.
- **Additional port export capacity plans increased from last year, to 253 Mtpa.** This increase accounts for planned new export ports in Russia and capacity expansion in Mozambique, although most of this capacity will not be constructed in the near term.
- **Despite some progress, carbon capture and storage (CCS) still needs very strong stimulus and serious commitment by governments.** Without greater government commitment, CCS will not progress to anywhere near the level required for a low-carbon energy system.

Box 5.1 Are low coal prices driven by climate policies?

In last year's 2015 *Medium Term Coal Market Report* we posed the question whether the decline in coal prices was being driven by climate policies since there were many opinions suggesting that the price of coal would not ever recover due to curtailment by strong climate policies. In a simple exercise, we compared copper, iron ore, steam coal and coking (met) coal prices from 2006 to 2014 (see Figure 5.3 in IEA, 2015) and observed that the trajectories of these four commodities followed similar trends, suggesting that macroeconomic developments play a big role in the commodity cycle. However, steam coal outperformed iron ore and coking coal, both of which were barely affected by climate policies. Repeating the exercise this year (see Figure 5.1), we observe that steam coal has continued to outperform copper, coking coal and iron ore since 2015.

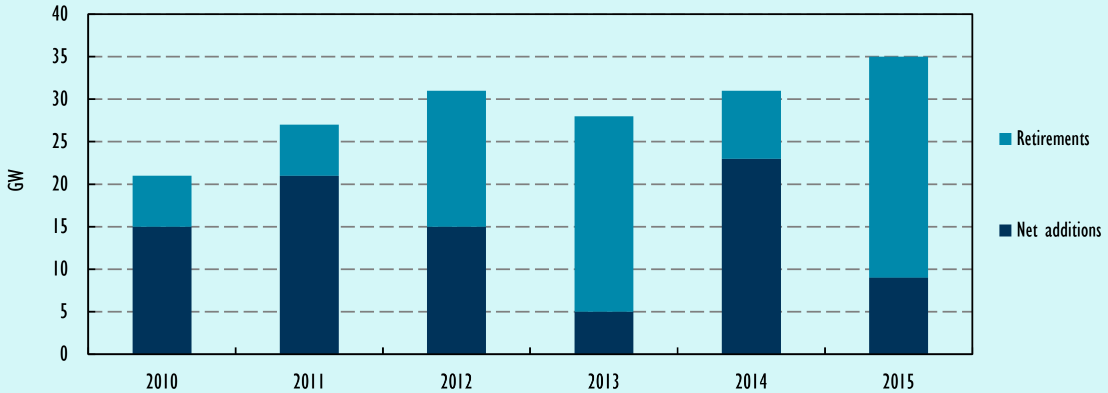
Figure 5.1 Indexed real commodity prices of copper, iron ore, steam and met coal



Box 5.1 Are low coal prices driven by climate policies? (continued)

As discussed in Chapter 2, although supply discipline among international seaborne exporters is yielding results, the main driver of coal price increases has been policy changes in China designed to cut oversupply. There were production cuts in places like Indonesia and, more importantly, lower capacity because no new large-scale supplies came on line and investments were reduced following coal price drops. This did, indeed, affect prices, but the greatest influence came from Chinese policies, especially the reduction of working days from 330 to 276, which cut production and increased costs, pushing up prices.

Figure 5.2 Coal plants commissioned and retired in 2010-15 outside China

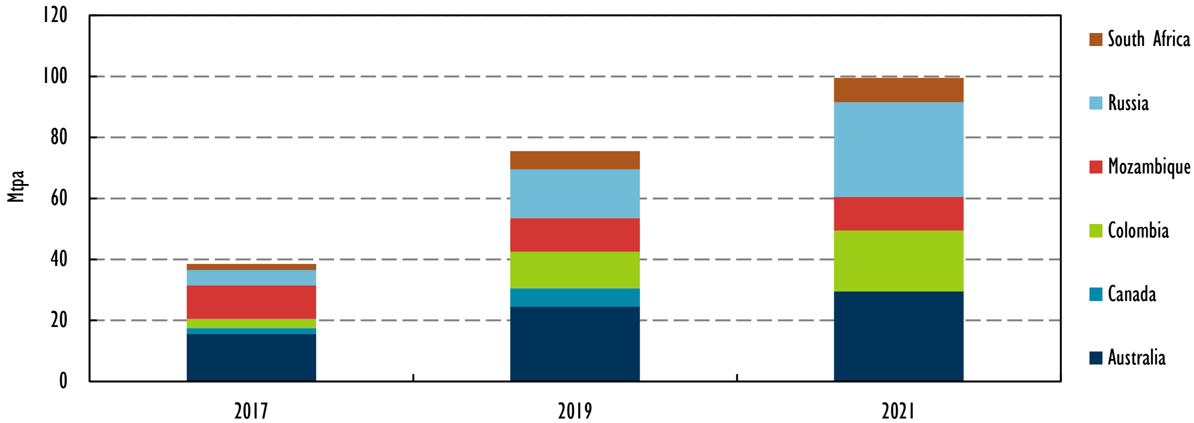


Regardless of whether coal prices rise or fall, it is undisputable that climate policies are reducing coal consumption, especially in the power sector, which is the main market for thermal coal, where there are more alternatives for substitution; the evolution of the coal-fired generation fleet indicates the scale of the impact. Figure 5.2, which excludes China since its large size eclipses developments elsewhere, shows that 35 gigawatts (GW) of new coal generation capacity were commissioned in 2015 outside China, the largest increase since 2010. Whereas commissioning of coal power plants maintained a strong pace, net additions were below 10 GW because of a large wave of retirements in both Europe and the United States in 2015. In Europe, 2015 was the deadline for the Large Combustion Plant Directive, and in the United States, for the Mercury and Air Toxics Standards (MATS). Retirements have therefore been driven by air quality legislation rather than by climate change policies; however, these circumstances should not be considered in isolation since the decision to close plants usually results from a combination of both: the investments needed to comply with environmental regulations are not committed because of the risks and poor prospects that climate change policies impose, as well as depressed wholesale market prices owing to increased wind and solar power generation. Final investment decisions or orders for new plants are better indicators of policy influence on coal price because plants commissioned today are the result of decisions made in the past, but exhaustive and accurate data on this are more difficult to collect.

Investment in export mining capacity

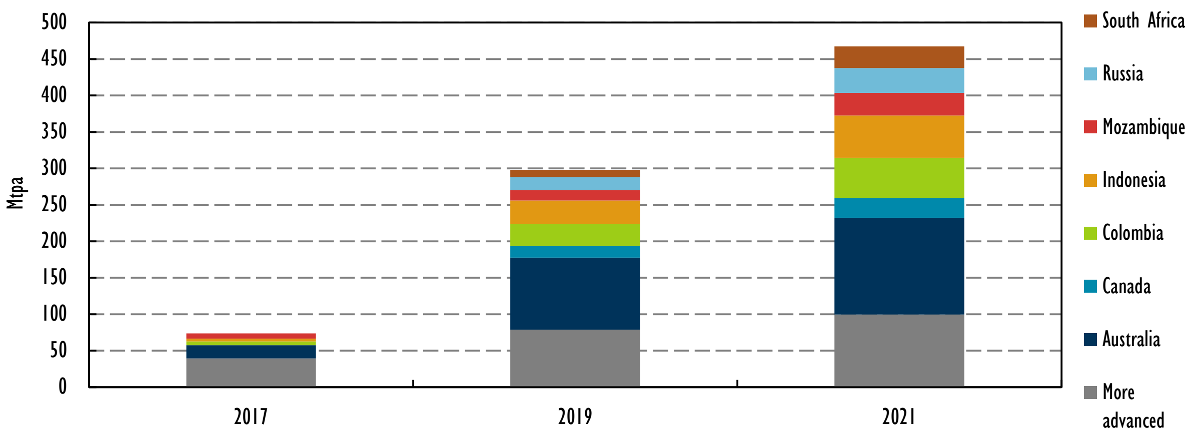
In previous editions of the *MTCMR*, export mining capacity projects were classified as "probable" or "potential". This terminology is misleading, however, as low coal prices mean most of the probable projects will not make significant progress and potential projects are very unlikely to be followed through. This report therefore defines projects either as "more advanced", meaning they have been approved or committed, or are under construction, and "less advanced", meaning they are at the feasibility or environmental impact study stage, or are awaiting approval.

Figure 5.3 Cumulative capacity of more advanced hard coal export mining projects, 2017-21



About 100 Mtpa of total new export mining capacity under development is classified as more advanced. Russia and Australia will each host around 30% of the additional global mining capacity, and Colombia follows with a 20% share of projected new capacity. Mozambique also has a significant amount of additional capacity classified as more advanced, but owing to infrastructure problems, projects in Mozambique are highly uncertain. Overall capacity from new projects has increased slightly from that reported in the *MTCMR 2015*. However, this slight rise is more owing to a lack of progress on projects (because of low coal prices) than to new additions, which are almost limited to just several new coking coal mines planned in Canada and the United States.

Figure 5.4 Cumulative capacity of hard coal export mining projects, 2017-21

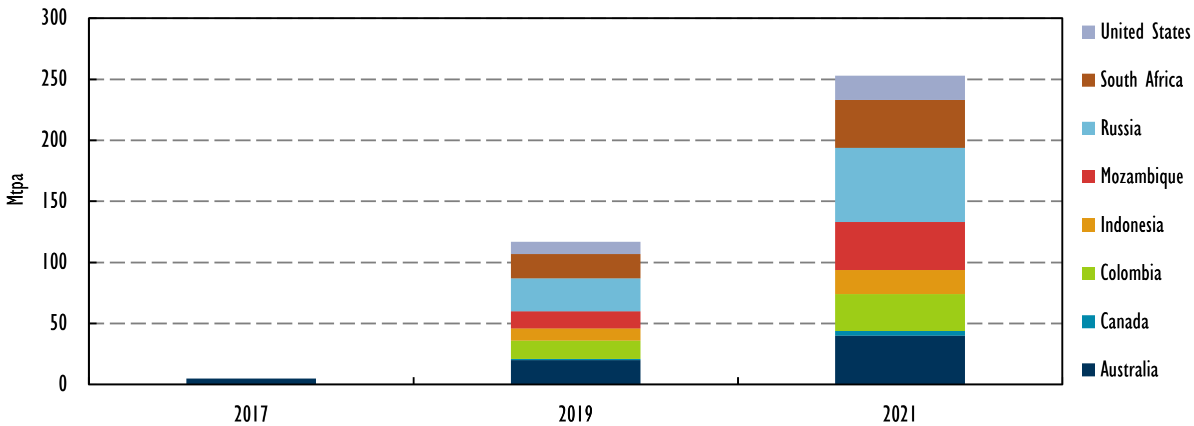


Less advanced export mining capacities in development amount to 368 Mtpa. Australia, with a share of 36%, has the largest capacity. Less advanced capacity additions have decreased from last year's report largely because the capacity of the Carmichael mine in Australia was reduced by 40 Mtpa. That the amount of less advanced capacity additions remains high despite unfavourable market conditions can be explained by the fact that companies tend to keep their early-stage investment projects intact rather than cancel them. They can then wait for market prices to recover, to avoid writing off assets on their balance sheets.

Investment in export infrastructure capacity

Export infrastructure investments generally have lead times of several years, similar to investments in export mining capacity. Tracking projects currently under construction or in the planning stage therefore makes it possible to estimate the amount of additional export infrastructure capacity that may become operational in the medium term. Sufficient infrastructure capacity is a condition for a mining project to go ahead. Congestion of export ports or railways can limit the export capacity of a newly built or expanded mine. Coal-exporting countries, especially Mozambique and to a lesser degree South Africa, have been strongly affected by insufficient infrastructure in recent years.

Figure 5.5 Projected cumulative additions to coal terminal capacity, 2017-21



Total new port export capacity is 253 Mtpa; this is higher than *MTCMR 2015* projections. This increase in capacity is mainly the result of new plans to build coal export ports in Russia, as well as a capacity expansion in Mozambique. Plans for large capacity expansions, particularly in Russia and the United States, aim to increase coal exports to Asian markets, but there is no guarantee these projects will go ahead. For instance, projects planned for the Pacific coast of the United States are not expected to become operational over the outlook period, if ever. Significantly expanded port capacities in Mozambique and South Africa are also planned, to alleviate bottlenecks limiting export capacity. It is noteworthy that the number of projects expected to come on line in the short term has decreased from last year's report, as various projects have been postponed as a result of low market prices. Given that the price increase of this year is more related to policy changes in China than to market fundamentals, and considering that the structural oversupply in China will continue in the coming years, we expect prices to decline in the short term below USD 70/t, to increase by the end of the outlook period.

Regional analysis

In the following section, current investment projects in coal mining and export infrastructure over the outlook period are analysed.

Australia

Investment in export mining capacity

In Australia, one new coal mine project has entered commercial operation since publication of the *MTCMR 2015*: Anglo American's Grosvenor underground mine, built in Queensland, produced its first longwall met coal in May 2016. The mine is expected to produce 3.2 million tonnes (Mt) in 2016, before reaching its designated production capacity of 5 Mtpa. The Maules Creek met/thermal coal mine, which started operation in December 2014, was able to ramp up production considerably during the fiscal year 2015-16, with production reaching 7.3 Mt from 1.8 Mt the previous year. Whitehaven expects to produce about 10 Mt in 2017, and aims to reach its designated production capacity of 12 Mtpa in 2018.

There are 29 Mtpa of more advanced mining capacity. A large portion of the new capacity is in Queensland, while the rest is in New South Wales. The forecast capacity of more advanced projects has decreased since the *MTCMR 2015*. Among the more advanced new capacity, two new coal mines are planned to start production during the outlook period. In Queensland, the Eagle Downs coking coal mine of Baosteel Resources and Vale, having a capacity of 4.5 Mtpa with an investment of USD 1.3 billion, is to become operational by 2017. The Byerwen project, with a planned capacity of 10 Mtpa and scheduled to start operation in the third quarter of 2016, will be operated as a joint venture between QCoal and JFE Steel. Initial production capacity will be limited to 2 Mtpa because only one of the six mining leases has been secured so far. Other more advanced capacity expansion projects include the met coal mines Baralaba North, Metropolitan and Appin Area 9.

Total less advanced capacity addition projects in Australia amount to almost 133 Mtpa, with a large portion coming from projects in the newly developed Galilee Basin. However, there are considerable obstacles to development of the Galilee Basin. To export coal from the port at Abbott Point, a 500-kilometre (km) railway needs to be built, and although the mining company GVK Hancock and the railway company Aurizon had announced plans to build the necessary railway connecting the mining region to the port, Aurizon stated in February 2016 that it has written off its losses and will no longer take part in the project. Under current circumstances, development of the Alpha Coal project (32 Mtpa), Alpha West (24 Mtpa) and Kevin's Corner (30 Mtpa) are therefore unlikely to be realised during the outlook period. Other projects in the Galilee Basin, such as China First (40 Mtpa) and China Stone (55 Mtpa) are also expected to be delayed significantly because of lack of access to infrastructure. Among the less advanced projects in the Galilee Basin, Adani's Carmichael project is the only one to have advanced considerably. The project also involves construction of the North Galilee Railway and expansion of the Abbott Point port. In 2016, however, it was announced that the Carmicheal mine's planned capacity of 60 Mtpa had been reduced to 20 Mtpa.

Investment in export infrastructure capacity

The total coal export capacity of Australian ports in 2015 was 533 Mtpa. Since last year's report, only the capacity expansion of Hay Point Terminal has been realised. With completion of a new third berth in December 2016, the export capacity of the port rose from 44 Mtpa to 55 Mtpa. In August 2016, coal export operations at Barney coal terminal in Gladstone ceased with the commissioning of the nearby Wiggins Island Coal Terminal.

There are currently no additional port projects under construction, although several have reached the advanced planning stage. In October 2015, the government of Queensland approved Adani's Port of Abbot Point expansion project. When the 70 Mtpa expansion is completed, the coal export capacity of the port should reach 120 Mtpa; the expansion largely aims to facilitate coal exports from Adani's planned Carmichael mining project. The project faces opposition, however, owing to concerns of potential damage to the Great Barrier Reef, and a local organisation took the company to court in June 2016. There are also plans to expand the newly opened Wiggins Island Coal Terminal by 54 Mtpa, for a total capacity of 84 Mtpa.

In Australia, railway capacity has traditionally been a limiting factor for coal exports. This problem has been remedied to a certain extent by the construction of additional infrastructure in recent years, as well as several railway projects that became operational in 2015. Goonyella rail system expansion was completed in November 2015, extending the rail capacity of the Bowen Basin and the Port of Hay connection by 11 Mtpa. In October 2015, Aurizon opened the Hexham Train Support Facility in the Hunter Valley. Located near the Port of Newcastle, the facility will provide trains with supplies and aims to alleviate railway capacity constraints.

There are also other potential Australian railway infrastructure projects in the works that would affect coal exports. Adani is considering building a 500-km North Galilee Railway between the Carmichael coal mine and the port of Abbot Point. Another proposed project is the Surat Basin Railway, which would link the Western railway line with the Moura railway line; the time frame of this project has not been finalised, however, because of the uncertainty of mining projects in the region.

Colombia

Investment in export mining capacity

New projects in Colombia over the outlook period are mainly capacity additions for thermal coal. The acquisition of the Brazilian-listed CCX's coal assets by Yildirim Holding has been delayed. These assets include the Canaverales and Papayal open-cast mines – both with capacities of 2.5 Mtpa – and the 16 Mtpa San Juan underground project, as well as infrastructure assets such as a port and a railway. Canaverales and San Juan mining projects were initially expected to be operational by 2019, and the Papayal project in 2017. Commissioning may be delayed, however, since the acquisition process has been ongoing for several years already. Further projects are the expansion of Drummond´s El Descanso to 12 Mtpa of capacity and the Cerrejon mine, which aims to reach a capacity of 60 Mtpa by 2020.

Investment in export infrastructure capacity

Export and inland transport capacity are expanding in Colombia, with several projects being developed to increase export capacity and eliminate bottlenecks. In the first half of 2016, the first 0.2 Mt of coal was shipped from Puerto Brisa, which was commissioned in December 2014 (its late start was caused by weak coal prices in 2015). The port has a capacity of 3 Mtpa, but there are plans to expand it to 30 Mtpa. The second phase of the proposed project includes a railway link connecting the port to coal mines in the Colombian interior. In addition, a new USD 40-million direct-loading port with a 2 Mtpa capacity was commissioned in Barranquilla, 17 km from the mouth of the Magdalena River on the Caribbean coast.

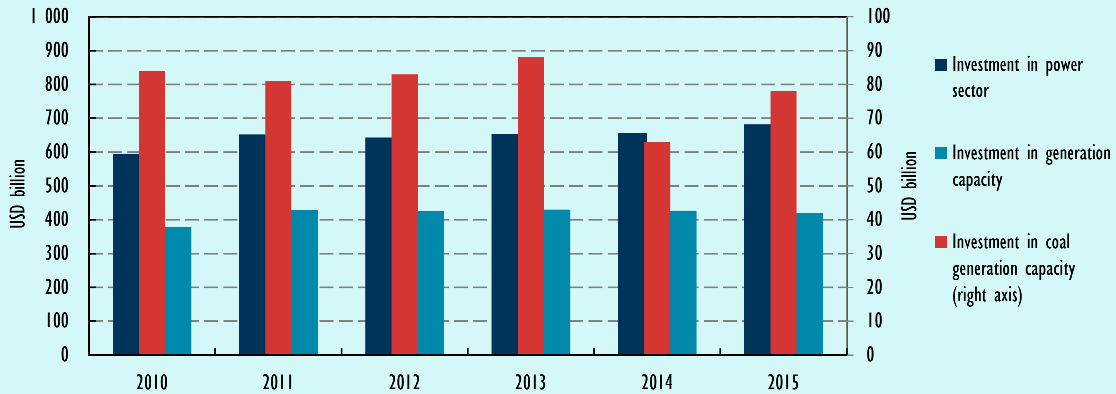
To alleviate bottlenecks and improve railway infrastructure, several projects have been proposed, and in certain cases are already under construction. Fenoco, which currently uses the Colombian Railway System to transport coal to Santa Marta, is building a parallel line to alleviate bottlenecks, exacerbated by the ban to operate at night. Construction work on the parallel line is 80% complete, and the remaining 38 km is to be completed in one or two years, expanding its capacity from 80 Mtpa to 150 Mtpa.

Box 5.2 The end of financing for coal power plants?

In 2015, global investment in the power sector was USD 682 billion, of which USD 420 billion was directed to generation capacity. Coal power generation claimed 18.5%, or USD 78 billion of power generation investments. Investment figures for 2015 follow the trends of recent years (Figure 5.6). Whereas investment in generation capacity in 2015 was 1% above the 2010-14 average, investment in coal capacity was 3% below.

Although coal power generation investments of USD 78 billion in one year may seem impressive, it is only 4% of the USD 1.8 trillion invested in the energy sector in 2015. Coal investments are penalised by the policies of many international financial institutions, investment funds, banks, university funds and other players, in particular those operating in the United States and Europe which have announced they are turning away from financing coal, or will impose increasingly stricter conditions for involvement in coal projects. Conditions apply to countries or regions in which coal plants are financed, and to the performance of the coal plants, usually in the form of high standards for efficiency and emissions. Therefore, the question of whether a proposed new coal power plant will secure financing is not an easy one. Irrespective of fuel choice, risk is the most important consideration for investors and financiers: 95% of investment in power generation in 2015 was supported by vertical integration, long-term contracts or price regulation. Most investments were made by state-owned companies, which usually have better access to capital than private investors. More than two-thirds of the generation capacity commissioned in 2015 was by state-owned companies, less than 30% was by private companies, and the remainder by mixed consortia.

Figure 5.6 Investment in the power sector, generation capacity and coal power generation



From a regional perspective, most investment is concentrated in Asia, mainly in China and India. For example, out of 87 GW of coal power plants commissioned in 2015 in the world, there were 52 GW in China, 19 GW in India and 16 GW in the rest of the world. Regarding plants under construction, about 200 GW are in China, over 60 GW are in India and over 60 GW are in the rest of the world, half in the ASEAN region. Therefore, any policy restricting financing for new coal plants in places such as Europe or the United States will have only a negligible impact at the global level.

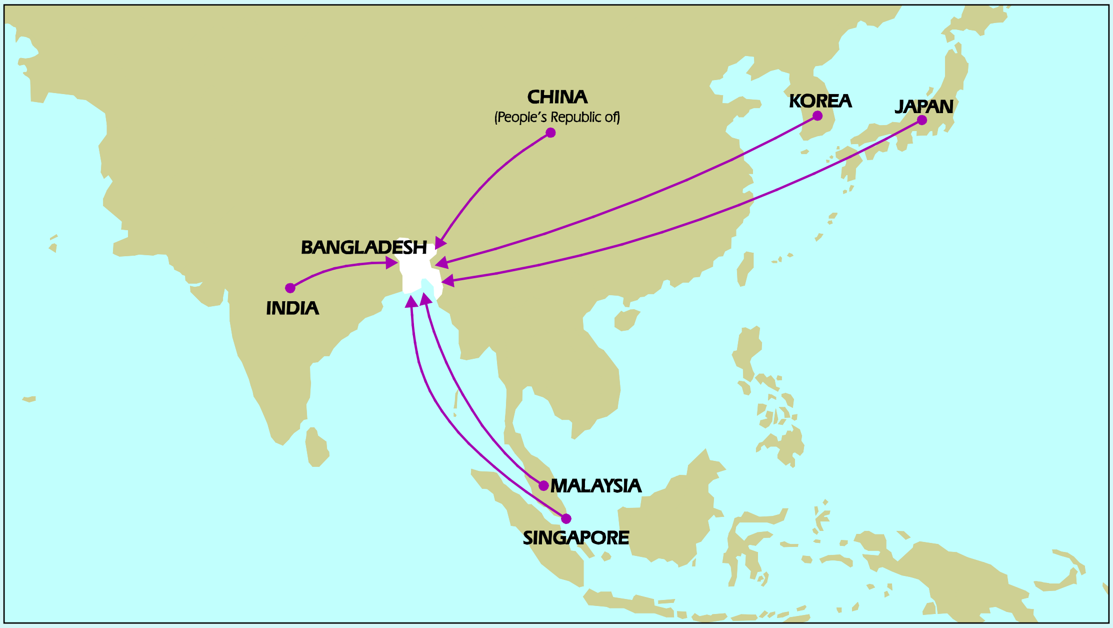
Whereas assessing the destination of funds is straightforward, tracking their origin is not. They can be balance sheet-financed, but even if they are project-financed it is not possible to track them because of the different ways projects are funded, the different channels through which monies are provided and the difficulty in knowing the actual amount provided by some fund, insurance or back-up providers. In fact, most of the capital was raised in China, mostly by state-owned utilities that find money easily to finance coal development. Likewise, in India during the last decade, excitement about the power sector

Box 5.2 The end of financing for coal power plants? (continued)

enabled investors – not only the National Thermal Power Corporation (NTPC) and the state-owned utilities, but many independent power producers (IPPs) that had joined the power sector – to mobilise large amounts of money, particularly for coal power generation. Excitement has since ebbed amidst delays, overruns and the long-standing issue of electricity tariffs being set below cost.

In other places, raising money is a real issue. In Bangladesh, for example, with a population of over 160 million people consuming around 300 kilowatt hours (kWh) per person per year (well below one-tenth the average of developed countries), finding capital for new coal power plants is a challenge, especially with many Western institutions placing increasing restrictions on coal financing. Investors in Bangladesh have primarily sought money in Asia, having signed memorandums of understanding (MoUs) and contracts to finance coal projects with companies and institutions from China, India, Japan, Korea, Malaysia and Singapore. Nevertheless, it is yet to be seen whether financing for these projects will be secured.

Map 5.1 Main origin of funds for announced coal plants in Bangladesh



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

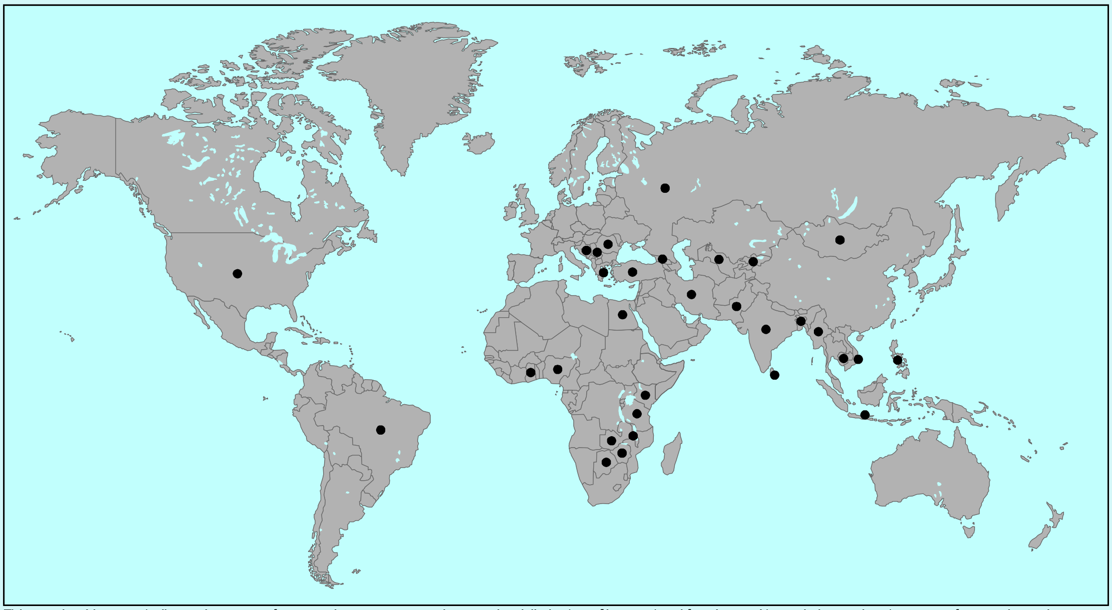
To strike a balance between addressing energy poverty and fighting climate change, in November 2015 the Organisation for Economic Co-operation and Development (OECD) Export Credit Group agreed on new export credit rules for coal power plants: financing support can be allowed only in poor, electrified countries provided that coal plants use ultra-supercritical (USC) technology* and that low-carbon options are not viable. This method of balancing energy access with climate change concerns demonstrates how conditions imposed by lenders – such as regulations for higher efficiency and lower air pollutant emissions – play an important role in shifting technology in new plants from subcritical to supercritical (SC) or USC. Japan is a good example of this shift, as its coal exports are mostly from SC/USC technology.

Chinese overseas plants have also become less polluting and more efficient over time, although subcritical plants are still being built. Map 5.2 shows the countries in which Chinese companies have

Box 5.2 The end of financing for coal power plants? (continued)

announced, are building or have built coal power plants. Even considering that some of the announced plants will never be built, activity of Chinese companies in the export market is significant.

Map 5.2 Presence of China's proposed, existing or under-construction power plants



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

* There are exceptions for plants smaller than 500 megawatts (MW) in International Development Association (IDA)-eligible countries that are geographically isolated.

Another railway project, construction of the Carare line, is still seeking funding. The 910-km Carare line would allow 10 Mtpa of met coal from Boyaca or Cundinamarca to be transported to ports on the Caribbean coast, and would reduce transport costs by 40%. There are also plans by private investors to build a road connecting Tunja in the Boyaca department, and Puerto Araujo, to Ruta del Sol, which is a key highway connecting interior regions with ports on the Atlantic coast. The 202-km road project, with a capacity of 8 Mtpa, is expected to cost about USD 850 million and reduce trucking costs by up to 25%. Construction is intended to start in 2017. Additionally, the government is hoping to rehabilitate the Magdalena River waterway to improve the transport of coal by barges.

South Africa

Investment in export mining capacity

The New Clydesdale Colliery, bought by Universal Coal from Exxaro in 2014, restarted operations in 2015. The mine is projected to have an initial production capacity of 0.9 Mtpa, which will largely supply the utility Eskom. In the long term, there are plans to ramp up its capacity to 2 Mtpa, including export capacity of 0.5 Mtpa. As part of its mine replacement project, Sasol brought the Impumelelo mine into operation, with a short-run capacity of about 9 Mtpa. Sasol's similar Shondoni project was expected to start production in 2016 with a capacity of 9 Mtpa. Both of these projects will supply coal exclusively to the Sasol Synfuels plant with conveyors, and are therefore not considered export mining capacity.

There are numerous plans for new investments and expansions in South Africa. Thermal coal producer Resource Generation (Resgen) aims to proceed with its 6-Mtpa Boikarabelo project, but has been contending with financing issues for several years now. The Waterberg Coal Company (WCC) expects to start production with its export coal mine in the Limpopo province in 2016, having a capacity of 2 Mtpa in the short term with plans to reach 4 Mtpa over a six-year period. South Africa's Coal of Africa Limited (CoAL) gained financial support from companies in Singapore and China to develop coal operations in Limpopo province with a capacity of 5.5 Mtpa. However, operations planned to start in the first half of 2016 have been delayed because of recent suspension of the project's Integrated Water Use License. Exxaro Resources is expanding its Grootegeluk mine to supply 14.6 Mtpa to the domestic market for Eskom's Medupi power station, and it additionally plans to develop the new Thabametsi mine. The mine is also planned to supply around 17 Mtpa to the domestic market for power generation, but an additional almost 3 Mtpa will be available for other markets.

Investment in export infrastructure capacity

The major coal export route out of South Africa is the Richards Bay Coal Terminal (RBCT), which has a capacity of 91 Mtpa. However, only 70 Mtpa to 80 Mtpa of its capacity is currently used, mainly owing to bottlenecks in the railway infrastructure. Nevertheless, there are investment plans for upgrading and to replace old equipment in the terminal. The first steps toward expansion are scheduled to be completed in August 2017 and January 2018. An additional expansion yielding "Phase 6" of the terminal's operations was to include a capacity expansion of 19 Mtpa, but plans were put on hold due to unsuitable market conditions.

Grinrod also intends to develop an export terminal at Richards Bay in a joint venture with RBT Resources. The terminal will have a capacity of 3 Mtpa, and there are plans for expansion up to 20 Mpta by 2017. Transnet's plans to install an additional terminal at Richards Bay have stalled, as an ongoing dialogue with RBCT and Grinrod indicates their expansion plans may suffice, making those of Transnet redundant. Transnet also launched a new tariff scheme to make exports possible for small mining companies, offering them a lower shipping cost at the underutilised RBCT. Furthermore, junior mining companies will gain access to 4 Mtpa of export capacity at the RBCT, supplemented by additional rail and port access provided by Transnet.

There are also negligible amounts of South African coal exported via Maputo. The Port of Maputo has been recently dredged and now can serve 80 000-tonne ships. Additionally, Grinrod plans to expand its dry-bulk terminal at the Maputo port. The fourth phase of this expansion, now at the advanced feasibility stage, involves a capacity increase from 7.5 Mtpa to 20 Mtpa.

Transnet will operate the first-phase upgrade of the Lephalale Mpumalanga railway, which will raise its capacity from 4 Mtpa to 23 Mtpa. Waterberg recently finished the first phase of the coal railway line connecting Lephalale and Richards Bay: construction of a 1.8-km loop at Matlas to increase capacity from 0.4 Mtpa to 2 Mtpa. The second phase has already started and will boost capacity to 6 Mtpa. Another proposed Waterberg rail line connecting Lephalale and Central Basin is planned to become operational in 2018 at the earliest, with a capacity of 23 Mtpa. Railway capacity is also being expanded through the coal link project connecting Mpumalanga and Richards Bay, with a projected capacity of 15 Mtpa in 2017. The Mpumalanga network will also connect several coal mines and power plants to the Mpumalanga-Richards Bay link.

Mozambique

Investment in export mining capacity

Since the vast, undeveloped reserves in the Tete province of Mozambique first gained the attention of large international mining companies, and since the enthusiastic investment phase of 2010-12, investments in additional capacity have decreased considerably. Low coal prices in international markets, serious infrastructure deficits in Mozambique, and various detrimental government policies as well as growing unrest in the country are largely responsible for the declining interest in mining operations. For example, International Coal Ventures Private Limited (ICVL) stopped operations at its Benga mine because of rail access charges, and negotiations with the government have still not reached a conclusion. After Rio Tinto cut its losses in Mozambican projects in 2014, Vale became associated with Mitsui to develop its assets there.

Despite concerns of Vale exiting Mozambique, the expansion of its Moatize mine has entered its second phase: capacity is targeted to reach 22 Mtpa eventually. ICVL has announced plans to increase annual production at its Benga mine to 13 Mtpa in coming years, from its current 5 Mtpa. Other large-scale mining projects are the Revuboe mine (owned by Talbot group, Nippon Steel & Sumitomo Metal Corporation, and Posco), the Zambeze Benga mine (ICVL) and the Ncondezi mine.

Investment in export infrastructure capacity

A lack of infrastructure has long been a handicap of Mozambique's coal industry. Until recently, the Sena rail line was the sole railway, and Beira was the only port for coal exports. The new 912-km Nacala rail corridor project remains the most important infrastructure project, as it will relieve traffic on the Sena line considerably by connecting the Moatize basin to the port of Nacala. The Nacala railway started operations in 2015 and is expected to bring Mozambique's export capacity up to 24 Mt when it becomes fully operational in 2018; within the first seven months of 2016, 3 Mt of coal had been exported via the Nacala line.

Construction of the 530-km railway line connecting Moatize with the port of Macuse is planned to begin in the first quarter of 2017. The USD 3-billion project involves construction of a deep seaport with a capacity of 25 Mtpa, and an additional 120-km expansion to reach unconnected coal deposits is also being considered. The 575-km rail line connecting Moatize and the port of Beira was expanded to allow for longer coal trains, and is now capable of transporting 20 Mtpa, compared with 6.5 Mtpa in 2013. The government also has plans to expand Beira's port capacity to 20 Mtpa from its current 6 Mtpa.

Russia

Investment in export mining capacity

Despite a large portion of its coal production being destined for domestic consumption, Russian export quantities are expected to increase: the Russian government has ambitious plans to achieve a 45% increase in coal exports by 2030. The majority of coal deposits to be developed in the medium term as part of this scheme are located in the eastern regions of Elginskoye and Denisovsky in the Sakha Republic, Mezhegeyskoye and Elegetskoye in the Tuva Republic, and Apsatskoye in Zabaykalsky Krai.

The Amaam North Project F of Tiger Realm Coal (TIG) is scheduled to be operational by 2017 with a capacity of 10 Mtpa. Once completed, the coking coal project will be one of the most cost-effective operations in the world. TIG also signed an agreement with the regional government of Chukotka to promote development and infrastructure at the Beringovsky coal basin. It plans to start metallurgical coal projects in the region in 2016, aiming for a production capacity of 0.5 Mtpa by 2018. The coal is to be exported through the Beringovsky and newly proposed Arinay ports. The Russian coal company SUEK has plans to develop the Apsatsky open-cast mine in the Zabaikelye region with a production target of 3 Mtpa by 2025. The first stage of this operation, including a coal preparation plant with a capacity of 1.5 Mtpa, is already in place. The new mine of Razrez Arshanovsky, with a planned full capacity of 10 Mtpa, started operations in 2015 in the Khakassia Republic and aims for an initial production capacity of 5 Mtpa by 2017. Similarly, Mechel plans significant capacity expansion of its Elga coal mine in South Yakutia: having started with limited production in 2014, the company targets production capacities of 8 Mtpa by 2017 and 30 Mtpa by 2023. Other new mining projects include the Elegest mine, which is scheduled to be operational by 2020 with a capacity of 15 Mtpa, and the Karakanskoe mine with a capacity of 6 Mtpa by 2017. SUEK plans to expand the capacity of its Urgal mine by 3 Mtpa in 2016. Similarly, capacity at the Solncevskoe deposit is planned to rise by 5 Mtpa in the coming years and an additional 5 Mtpa by 2020.

Investment in export infrastructure capacity

Russian coal exports to the Pacific Basin have been growing in recent years. As a result, eastern regions are receiving more attention in relation to new export infrastructure projects in Russia. Nevertheless, there are still plans to expand port capacities on the Black Sea to support exports to the Atlantic Basin. On the Pacific coast, the government is considering plans for two new coal loading ports in the Primorye region. The Vera project aims to have an export capacity of 20 Mtpa by 2019, and the Sukhodol project is similarly planned to operate at a total capacity of 20 Mtpa by 2021. However, a cut in state funding for the two projects has caused some uncertainty: the Vera project and the Sukhodol project remain dependent on international funding. As part of the Vanino railway terminal infrastructure expansion, SUEK commissioned a rail spur connecting the Toki freight yard and the Vanino Bulk Terminal. The whole programme, which started construction in 2013, is expected to eliminate loading bottlenecks and increase the capacity of the Vanino Bulk Terminal from 12 Mtpa to 24 Mtpa by 2017. Additionally, there are plans to construct a new 24-Mtpa terminal at Vanino to be operational by 2020. The capacity of the Vostochny port is planned to be expanded to 24.5 Mtpa in 2017, 29 Mtpa in 2019 and finally 39 Mtpa in 2020 with completion of the third phase of its modernisation and expansion plan. Further projects include a proposed new port in Arinay as well as expansion of the smaller Posiet and Maly ports. Construction of the Taman port, with a capacity of 10 Mtpa, is the only project planned for the Black Sea coast.

Russian Railways (RZD) is almost the sole railway operator in Russia; RZD’s investment programme therefore covers nearly all railway expansions in Russia. RZD plans an expansion of the Trans-Siberian and Baikal-Amur mainlines by 2018, which will increase their total transport capacity to 120 Mtpa. Furthermore, a new railway line has been proposed to connect the Elegest coal mine and Kuragino, linking South Siberian coal deposits to the Pacific coast ports. In addition to these expansion plans, China, Russia and Mongolia agreed to develop a northern rail corridor connecting Tianjin Port at China’s east coast to the Trans-Siberian railway at Kuragino through Mongolia. In June 2016, RZD signed an agreement with SUEK to improve the efficiency of coal transportation and increase the overall capacity of export facilities and railway infrastructure.

Indonesia

Investment in export mining capacity

In Indonesia, there are no publicly available comprehensive lists covering planned export capacity additions. All export mining capacity additions are therefore classified as less advanced projects.

The Haju mine began operation towards the end of 2015, and 0.3 Mt of met coal was produced in the first quarter of 2016. The mine is expected to have a capacity of 5 Mtpa when it is fully developed. The IndoMet mine complex project – of which the Haju mine is a part – consists of five deposits and covers a large area in Central and East Kalimantan. When completed, it will be the largest mine in Indonesia in terms of land area, reaching a production capacity of up to 20 Mtpa. The owners of the project were initially BHP Billiton and its local partner, the Adaro Group, but in the first quarter of 2016, BHP Billiton sold its 75% holding to Adaro; Adaro Energy also plans to develop the Mustika Indah Permai project in Sumatra. Another large mining project is the East Kutai Coal Project, with a thermal coal capacity of 30 Mtpa, which has been challenged by legal issues between the Indonesian government and the Churchill mining company over the project. The Cokal mining company's Bumi Barito Mineral project in Central Kalimantan is another less-advanced project. Cokal updated its resource statement for the eastern portion of the Bumi Barito Mineral project in the first half of 2016, indicating that the main resource is high-quality met coal with low ash, moisture and sulphur content.

Investment in export infrastructure capacity

Kereta Api Borneo (KAB), a subsidiary of RZD, is building a port in Balikpapan as one part of its large-scale infrastructure project in East Kalimantan. The port is planned to have 5 Mtpa of export capacity in the first year, expanding to 35 Mtpa by 2030. The Indonesian government had previously announced it would build 14 special coal export ports between Kalimantan and Sumatra Island to reduce exports of illegally mined coal, but in June 2016, plans for all 14 ports were put on hold. The government's goal of increasing domestic consumption, which will eventually restrict exports and reduce the need for new ports, is one of the main reasons for stalling the project. Moreover, there are doubts regarding the financial feasibility of the project.

Indonesia has various railway projects underway; however, current market conditions have delayed some of them. The state-owned railway company Kereta Api Indonesia (KAI) has postponed expansion of the Sumatra rail project to the end of 2016, originally planned to be completed by the end of 2015. The upgrade of the existing railway – which connects the Tanjung Enim mine of state-owned Bukit Asam (PTBA) to the Tarahan port – includes a capacity expansion from 22.7 Mtpa to 25 Mtpa. Another project that will be delayed is the railway connecting Muara Enim and Srengsem, with a projected capacity of 20 Mtpa: Bukit Asam Transpacific Railway, a subsidiary of PTBA, decided to put the project on hold as a result of low coal prices in recent years. However, development of the railway projects Muara Enim–Tanjung Api-Api and Muara Enim–Pulau Baai is expected to continue, each having a planned capacity of 20 Mtpa. In East Kalimantan, construction of the KAB railway project is expected to start in 2017. The railway will connect West Kutai with KAB's port project at Balikpapan.

Box 5.3 Carbon capture and storage: Critical for coal post-COP21

Successful implementation of the COP21 Paris Agreement will require renewed emphasis on carbon capture and storage (CCS) deployment, including for coal-fired power generation. The Agreement establishes two targets that should have given a boost to CCS: limiting average global temperature increase to well below 2°C, and achieving "a balance between anthropogenic emissions by sources and removals by sinks" in the second half of the century. Initial analysis by the International Energy Agency (IEA) on the implications of a well-below-2°C target indicates that the power sector may need to be virtually decarbonised by 2040, with a global average electricity generation carbon dioxide (CO_2) emissions intensity much lower than 78 grammes per kilowatt hour (g/kWh) in 2 degree scenario (IEA, 2016a). For comparison, current average CO_2 emissions of the global electricity fleet are more than 500 g/kWh, with coal-fired generation averaging 900 g/kWh. Unabated coal-fired power generation will therefore need to be virtually eliminated from the electricity mix if the emissions level required under a well-below-2°C scenario is to be achieved.

CCS projects: The 2020 cliff

Although deployment of CCS technologies continues to advance, it is at a much slower pace than that required to keep temperature rise under 2°C. As of November 2016, there were 15 large-scale CCS projects operating across a range of applications, including coal-fired power generation (Boundary Dam Unit 3 in Canada), coal-to-gas conversion, natural gas processing, steel manufacturing and hydrogen production (GCCSI, 2016a). Six more projects are expected to commence operations before the end of 2017, including the world's first large-scale bioenergy with CCS project. Two of the upcoming projects will apply CCS to coal-fired power generation: the Petra Nova Carbon Capture Project and the Kemper County Energy Facility, both in the United States.

CCS project deployment currently under way is largely the result of government funding programmes announced between 2007 and 2010. Eight of the ten projects that have either been commissioned since 2014 or are due to be by 2017 have received direct financial support from those CCS programmes, principally in Canada, the United States and Australia. This underscores the importance of government support for CCS project deployment, especially in light of the lengthy time frames that are often involved in developing first-of-a-kind, large-scale integrated projects.

Without new policy or financial measures, the momentum in CCS project deployment will likely stall by 2020. There has been limited CCS project activity in recent years, with no final investment decisions for large-scale projects announced since 2014. In fact, two prospective CCS projects in power generation – Peterhead and White Rose – were abandoned in the United Kingdom following cancellation of the GBP 1-billion CCS Commercialisation Programme in 2015.

Coal-fired power with CCS: Emerging experience

Experience with CCS applied to coal-fired power generation is expanding and diversifying. The Boundary Dam 3 CCS project has been operating for more than two years now, and as of August 2016 had captured more than 1 million tonnes of carbon dioxide ($MtCO_2$). The Kemper County Energy Facility will soon become the first project to demonstrate integrated gasification combined cycle (IGCC) technology with CCS, and the Petra Nova Capture Project will be the largest retrofit of post-combustion capture (PCC) technology. These projects are playing a critical role in supporting future widespread deployment of CCS on coal-fired power plants.

Box 5.3 Carbon capture and storage: Critical for coal post-COP21 (continued)

Boundary Dam Unit 3

The SaskPower Boundary Dam power plant is located in the Canadian province of Saskatchewan, which has a 200- to 500-year supply of lignite coal and relies on coal-fired power for around 50% of its power generation. The decision to rebuild and retrofit the original Unit 3 (built in 1969) of the Boundary Dam plant with CCS was driven partly by the alternatives to coal for power generation in the region being limited, and partly by Saskatchewan's coal resources being abundant and affordable (IEAGHG, 2015). The stability and predictability of the price of nearby lignite coal, particularly compared with gas, was also a factor. Further, SaskPower identified the potential to realise value from the sunk investment in the existing plant, rather than investing in a new plant, as well as the revenue that could be gained from the sale of its by-products: CO_2 for enhanced oil recovery (EOR), sulphuric acid and fly ash (IEAGHG, 2015). The rebuild is expected to extend the life of the unit by 30 years.

Table 5.1 Technical parameters of Boundary Dam 3

	Original	Rebuild (no capture)	Rebuild (with capture)
Commissioning date	1969	June 2014	October 2014
Electrical data (MW)			
Gross output	150	161.1	147.4
Station service	11	12.1	11.9
Capture station service	-	-	11.4
Compression	-	-	13.9
Net electrical output	139	149	110.2*
Emissions intensity (t/GWh)			
CO_2	1 040	-	130
SO_x	6.5	-	0
NO_x	2.2	-	1.21

* Includes all owner margins: actual output ranges from 115 MW to 120 MW.
Notes: t/GWh = tonnes per gigawatt hour; SO_x = sulphur oxide; NO_x = nitrogen oxide.
Source: Reitenbach (2015), "SaskPower's Boundary Dam Carbon Capture Project Wins POWER's Highest Award".

The rebuild of the original 150-MW subcritical Unit 3 involved replacing the 1969 turbine with a modern Hitachi dual-mode turbine with better steam and thermal integration, as well as the capacity to handle powering up or down of the CO_2 capture plant. The plant was designed to continue running at full load when the capture plant is switched off (IEAGHG, 2015). After the rebuild, the net electrical capacity of the unit was 149 MW, or 115 MW to 120 MW with CO_2 capture enabled. The CO_2 capture and compression application consumes a parasitic load of 25.3 MW (Table 5.1). The parasitic load of the PCC is one-third lower than what was expected when the retrofit was designed (IEAGHG, 2015).

After some initial problems during the first year of operation, the performance of the Boundary Dam plant has consistently improved. It captured around 426 000 tonnes of carbon dioxide (tCO_2) in 2015 and, as of end-September 2016, had exceeded 600 000 tCO_2. In September 2016, the plant operated for 100% of the hours in the month, capturing 77 111 tCO_2 (Exchange Monitor, 2016).

The decision to invest in Boundary Dam was made in 2008, prior to the 2011 announcement by the Canadian government that it would introduce strict emissions performance standards for new coal-fired power generation units and for units having reached the end of their "useful life". These measures, which came into effect in 2015, require that new coal-fired power plants have a CO_2 emissions limit of 420 t/GWh, which is roughly equivalent to the emissions intensity of a modern, high-efficiency natural gas combined-cycle plant. The useful life of units is defined in legislation and determined by the unit's commissioning date, but all plants reach the end of their useful life 50 years after commissioning. The retrofit of Unit 3 at Boundary Dam with 90% CO_2 capture has enabled it to comfortably meet the new emissions standards, with an emissions intensity of around 130 t/GWh (Reitenbach, 2015).

Box 5.3 Carbon capture and storage: Critical for coal post-COP21 (continued)

Kemper County

The USD 6.8-billion Kemper County Energy Facility includes a 585-MW IGCC plant with a base lignite capacity of 524 MW and natural gas capacity of 58 MW. The plant uses transport integrated gasification (TRIG) technology developed by Southern Company and KBR in conjunction with the US Department of Energy (MIT, 2016). TRIG technology is designed to operate at high efficiency rates (of around 43%) using low-rank and high-moisture-content coals. When operational, the Kemper IGCC plant will have a higher heating value (HHV) efficiency of 29.5% and a lower heating value (LHV) efficiency of 32.1% with CO_2 capture rates of 65% and coal moisture content greater than 40%. The Kemper plant will capture around 3 MtCO_2 each year and produce CO_2 emissions of around 800 pounds per megawatt hour (lbs/MWh) (Southern Company, 2010), enabling it to comply with EPA emissions standards of 1 400 lbs/MWh for new coal plants.

The Kemper Facility is situated in close proximity to an estimated 4 billion tonnes (Bt) of lignite, which has a high moisture and ash content (MIT, 2016). A new coal mine, the Liberty Mine, has been constructed with an estimated capital cost of approximately USD 232 million (MPSC, 2016). The Liberty Fuels Company, a subsidiary of the North American Coal Corporation, will operate the mine with a minimal annual management fee of USD 38 million beginning in 2014, for the 40-year lifespan of the mine (Southern Company, 2011). The mine will be the largest coal mine in Mississippi: at full capacity it will produce 4.4 Mtpa, or around 160 Mt over its 40 years of operation. This is the first example of a CCS-equipped power facility underpinning investment in a new coal mine development, but it may serve as a model for future thermal coal investments as governments introduce increasingly stringent climate policy measures.

Petra Nova Carbon Capture Project

The Petra Nova Carbon Capture Project is located at the W.A. Parish power plant, one of the largest generation facilities in the United States. The plant comprises four coal-fired units totalling 2 475 MW that use more than 30 000 t of coal per day, sourced from Wyoming's Powder River Basin. There are also six gas-fired units totalling 1 270 MW at the plant (GCCSI, 2016b), and the captured CO_2 will be used for EOR.

The CO_2 capture project is expected to commence commercial operations before the end of 2016 – on schedule, and on budget (Irfan, 2016). This will be a first for a large-scale CCS power project, and a significant achievement for a new technology application. The plant will capture around 90% of CO_2 emissions from a 240-MW slipstream (around 1.4 MtCO_2 annually) using technology developed by Mitsubishi Heavy Industries and KEPCO. A 75-MW natural gas generator has been built to provide the additional 45 MW of power required for the CO_2 capture facility (Wang, 2014). As a result, the retrofit will not result in a derating (reduction in the power rating) of the existing asset because steam and power from the base plant will not be redirected for CO_2 capture. The project is a significant scale-up from the 115-MW retrofit at Boundary Dam.

Coal-to-gas and CCS: The Great Plains Synfuel Plant and Weyburn-Midale Project

The Great Plains Synfuel Plant is one of the largest and longest-running CCS projects globally, having commenced CCS operations in 2000. The facility, owned by Dakota Gas, converts 18 000 t of lignite per day into more than 150 million cubic feet of natural gas (GCCSI, 2016c). The coal gasification process results in a CO_2 stream that is very dry and approximately 95% pure, and requires no further processing before being sold for EOR. Around 50% of the CO_2 from the coal gasification process is captured – roughly 3 Mt each year.

The CO_2 is transported via pipeline to the Weyburn and Midale oil fields in Saskatchewan, Canada. Approximately 2.4 Mtpa of the CO_2 is injected at the Weyburn field and 0.6 Mtpa at Midale. Between 2000 and 2011, the CO_2-EOR operations were monitored by the IEA Greenhouse Gas R&D Programme

Box 5.3 Carbon capture and storage: Critical for coal post-COP21 (continued)

(IEAGHG) Weyburn-Midale CO_2 Monitoring and Storage Project, the largest full-scale CCS field study ever conducted. It included study of the mile-deep seals that contain the CO_2 reservoirs, analysis of CO_2 plume movement, and the monitoring of permanent storage (IEA, 2016b). The CO_2-EOR operations continue today, but without the same level of monitoring.

Faster progress needed

Recent progress in CCS project deployment has been welcome, and the projects mentioned above will make a major contribution to the development of CCS technologies. However, a considerable escalation in current efforts will be needed if coal is to have an important place in the electricity mix as the world aspires to the high goals of the Paris Agreement. More experience with large-scale projects, including outside of North America, will be required to reduce costs and build confidence in the technology. In addition to the need for technology development, governments must establish stringent CO_2 emissions regulations and enforce them with substantial penalties if they wish to spur investments in CCS.

Canada

Investment in export mining capacity

Canada mainly exports met coal, the majority of it mined in the western provinces of Alberta and British Columbia. In recent years, however, several mining projects have been delayed, mostly owing to relatively high operating costs and the strong decline in global market prices.

Operation of the Vista thermal coal mine is indefinitely delayed, since a plan to economically produce and transport the coal has not yet been finalised. The Vista project, which the Cline Group acquired from Coalspur Mines in 2015 after Coalspur failed to fund the project, has a planned capacity of 13 Mtpa; the initial phase, with a capacity of 6 Mtpa, was originally expected to be operational by 2017. Glencore's proposed Sukunka project faced approval problems owing to environmental issues, and further development is uncertain. The open-pit met coal mine was to have a capacity of 3 Mtpa, with a further increase to 6 Mtpa.

The Murray River coking coal project has also been put on hold due to weak market conditions; it was intended to be operational by 2018 with a capacity of 6 Mtpa. The future of the proposed Crowsnest Pass mine in Alberta, with a capacity of 4 Mtpa, is uncertain since the area was declared protected by the federal government. Similarly, realisation of the Raven Underground Coal Project on Vancouver Island, with a capacity of 1.1 Mtpa, is becoming more unlikely since the Environmental Assessment Agency terminated the comprehensive study of the project.

There are also several mining projects in Canada that are continuing to be developed: for instance, the Donkin coal mine project in Nova Scotia is progressing, and the mine is planned to start operations when market conditions improve with an initial capacity of 1 Mtpa, which could later be increased to 3 Mtpa depending on the market. The Groundhog anthracite project, developed by Atrum Coal, is expected to produce 5.4 Mtpa after 2017; Atrum expects to start production at Groundhog in 2016, with an initial capacity of 0.9 Mtpa. An agreement was reached with the Stewart World Port to ship 5 Mt annually from the Groundhog mine starting in 2018. Additionally, James Resources' Crown Mountain Project is planned to be operational by 2018-19 with a capacity of nearly 2 Mtpa.

Investment in export infrastructure capacity

Capacity at western export terminals has been expanded in recent years to serve growing exports to Asia; however, the latest market developments have affected ongoing expansion plans. Plans for Ridley terminal, originally to expand capacity from the current 18 Mtpa to 24 Mtpa, are still on hold: a throughput significantly below existing capacity in 2015 prompted a decision to further delay the project. There are also plans to sell the terminal, Westshore Terminals being one of the potential buyers. An attraction for Westshore is Ridley terminal's large quantity of available land and the expansion potential it offers, as Westshore's current expansion potential is very limited by the absence of additional space in its terminal. In its own terminal, Westshore is conducting a USD 270-million capital project for upgrades. Also, the Fraser Surrey Docks, planning to build an additional coal terminal to export coal from the Powder River Basin, obtained permits at the end of 2015 to proceed with the project. The proposed terminal will have a capacity of 4 Mtpa and is intended to be operational by 2017.

United States

Investment in export mining capacity

Investment in additional export mining capacity is very limited in the United States as a result of weak domestic demand and low prices in international markets in the past few years. Nevertheless, with the recent strong rise in met coal prices that intensified during the third quarter of 2016, Ramaco announced plans to develop met coal mining capacities on its properties in Elk Creek and Berwin in West Virginia: additional production capacity of approximately 3.5 Mtpa is to become operational over several years, starting in 2017. In addition, Sunrise Coal, a Hallador Energy subsidiary, announced in 2015 its plans to extend the reserve base of its Oaktown 1 underground mine in Indiana through the acquisition of nearby reserves. The acquisition was completed in 2016, although no plans have been announced for an expansion of production capacity in the medium term.

Investment in export infrastructure capacity

To keep pace with increased coal demand in Asia in recent years, significantly enlarged port capacity has been planned for the US West Coast to alleviate bottlenecks, and especially to enable cost-competitive production at the Illinois and Powder River basins to operate at full export capacity.

Six additional coal terminal projects in the US Pacific Northwest were proposed for this purpose; however, only the Gateway Pacific and the Millennium Bulk terminals are still active, the four others having been cancelled. The Gateway Pacific Terminal, with a capacity of up to 48 Mtpa, was originally scheduled to be operational in 2017, but development was postponed because of permitting delays and the start of operations was eventually rescheduled for 2019. In 2016, however, the US Army Corps of Engineers denied the permit required for construction, so development of the terminal is quite uncertain. The Millennium Bulk Terminal, which is expected to have a capacity of 44 Mtpa, is progressing through the permitting procedures. In 2016, it was announced that the Millennium expansion meets the Environmental Protection Agency (EPA) environmental standards required to receive the necessary permits. An additional terminal in Oakland, California, with a capacity of 8 Mtpa was also proposed, but construction of the terminal, which was to be built on an old army base, is highly uncertain since the Oakland city council approved a rule in June 2016 blocking coal exports. There are also several plans for increasing export capacity at the Gulf of Mexico, such as expanding existing port capacity to 48 Mtpa by 2020, and establishing a new terminal with a throughput of 22 Mtpa. Export operations through the Gulf may have some benefit from the Panama Canal expansion, which was completed in 2016.

With the frequent bottlenecks in railway infrastructure in 2014 resulting from large coal export volumes and high oil and grain shipping demands, Burlington Northern Santa Fe (BNSF) and Union Pacific, the two main rail operators, had confirmed further investments in railway capacity. Coal exports have since declined significantly, however, so additional railway capacity may no longer be important, or may even be redundant. For instance, the CSX Corporation transported only 5 Mt of export coal in the first quarter of 2016 by rail, which is 40% lower than in the first quarter of 2015.

Poland

Investment in export mining capacity

The largest potential for additional future coal production capacity is in the Lublin Coal Basin. Australia's Prairie Mining received exclusive mining rights in 2015 to develop operations at its planned Lublin Coal Project (also called the Jan Karski Project). It is planned to produce about 6 Mtpa by 2020, at a relatively low cost. Prairie Mining judges its product to be sufficiently competitive to be exported to several countries, such as Turkey, Germany, Austria and the Czech Republic. In Silesia, New World Resources has completed a pre-feasibility study for its Debiensko underground coking coal mine project. The company is currently seeking funding for the project to enter a two-year feasibility study stage. Likewise in Silesia, the German company HMS Bergbau AG intends to develop its project in the Orzesze region through its Polish subsidiary, Silesian Coal. The project has a planned production capacity of 3 Mtpa and is expected to receive the required mining license by the end of 2016, to start operations by 2018. Polish KOPEX is also developing an underground project in Silesia (Przeciszow), where construction was originally scheduled to start by 2013.

Investment in export infrastructure capacity

There are no significant infrastructure projects planned to enter into service over the outlook period, but possible improvements may be established through the Silesian programme funded by Poland and the European Union. The programme aims to increase coal production in the region as well as improve corresponding road and rail infrastructure in the southern region.

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ANNEX

Table A.1 Coal demand, 2014-21, forecast (million tonnes of coal equivalent [Mtce])

	2014	2015*	2017	2019	2021	CAGR
OECD	1 433	1 343	1 277	1 234	1 205	-1.8%
OECD Americas	672	577	540	527	517	-1.8%
United States	617	523	492	483	475	-1.6%
OECD Europe	407	399	373	349	337	-2.8%
OECD Asia Oceania	354	367	364	358	351	-0.7%
Non-OECD	4 155	4 096	4 141	4 236	4 431	1.3%
China	2 896	2 797	2 749	2 743	2 816	0.1%
India	537	553	604	665	740	5.0%
Africa and Middle East	164	152	158	160	164	1.2%
Eastern Europe/Eurasia	295	300	300	303	306	0.4%
ASEAN	141	165	186	214	250	7.2%
Other developing Asia	86	93	103	107	111	3.0%
Latin America	36	37	42	43	44	3.0%
Total	**5 588**	**5 439**	**5 418**	**5 469**	**5 636**	**0.6%**
European Union	373	366	335	308	295	-3.6%

* Estimate.

Note: CAGR = compound average growth rate 2015-21, OECD = Organisation for Economic co-operation and Development

Table A.2 Thermal coal and lignite demand, 2014-21, forecast (Mtce)

	2014	2015*	2017	2019	2021	CAGR
OECD	1 250	1 160	1 092	1 050	1 023	-2.1%
OECD Americas	643	551	514	502	492	-1.9%
United States	597	505	474	466	458	-1.6%
OECD Europe	339	332	308	285	275	-3.1%
OECD Asia Oceania	268	277	270	264	256	-1.3%
Non-OECD	3 377	3 333	3 421	3 526	3 708	1.8%
China	2 277	2 197	2 185	2 202	2 275	0.6%
India	490	505	552	606	672	4.9%
Africa and Middle East	159	146	151	153	156	1.2%
Eastern Europe/Eurasia	212	216	228	229	230	1.1%
ASEAN	139	162	182	208	241	6.9%
Other developing Asia	80	86	97	101	105	3.3%
Latin America	20	22	26	27	28	4.3%
Total	**4 627**	**4 494**	**4 513**	**4 576**	**4 731**	**0.9%**
European Union	312	306	275	250	238	-4.1%

* Estimate.

Table A.3 Metallurgical (met) coal demand, 2014-21, forecast (Mtce)

	2014	2015*	2017	2019	2021	CAGR
OECD	183	183	185	184	182	-0.1%
OECD Americas	28	27	26	26	25	-0.9%
United States	20	18	17	17	17	-1.1%
OECD Europe	68	67	66	64	62	-1.2%
OECD Asia Oceania	86	89	93	94	95	0.9%
Non-OECD	778	763	720	710	723	-0.9%
China	618	601	564	542	541	-1.7%
India	47	48	51	59	68	5.9%
Africa and Middle East	5	6	7	7	7	3.3%
Eastern Europe/Eurasia	83	84	72	74	76	-1.6%
ASEAN	3	3	4	6	8	17.8%
Other developing Asia	6	6	6	6	6	-0.7%
Latin America	16	15	16	16	16	1.0%
Total	**961**	**946**	**905**	**894**	**905**	**-0.7%**
European Union	61	60	60	58	56	-1.0%

* Estimate.

Table A.4 Coal production, 2014-21, forecast (Mtce)

	2014	2015*	2017	2019	2021	CAGR
OECD	1 384	1 293	1 220	1 191	1 197	-1.3%
OECD Americas	757	663	600	565	570	-2.5%
United States	693	606	533	505	511	-2.8%
OECD Europe	215	203	185	181	177	-2.3%
OECD Asia Oceania	412	427	436	445	450	0.9%
Non-OECD	4 285	4 197	4 198	4 279	4 439	0.9%
China	2 699	2 618	2 580	2 594	2 666	0.3%
India	362	383	433	477	536	5.8%
Africa and Middle East	225	217	219	223	226	0.6%
Eastern Europe/Eurasia	422	416	413	429	431	0.6%
ASEAN	438	417	404	401	418	0.0%
Other developing Asia	50	56	53	56	59	1.0%
Latin America	88	90	97	98	103	2.4%
Total	**5 669**	**5 491**	**5 418**	**5 469**	**5 636**	**0.4%**
European Union	204	198	175	170	165	-3.0%

* Estimate.

Table A.5 Thermal coal and lignite production, 2014-21, forecast (Mtce)

	2014	2015*	2017	2019	2021	CAGR
OECD	1 088	1 006	919	903	909	-1.7%
OECD Americas	660	584	507	491	499	-2.6%
United States	625	552	471	459	468	-2.7%
OECD Europe	193	182	169	166	163	-1.8%
OECD Asia Oceania	235	240	243	246	247	0.5%
Non-OECD	3 596	3 518	3 592	3 669	3 818	1.4%
China	2 134	2 060	2 084	2 105	2 171	0.9%
India	357	379	426	470	530	5.8%
Africa and Middle East	216	209	211	215	217	0.6%
Eastern Europe/Eurasia	324	323	338	350	350	1.4%
ASEAN	437	415	398	393	408	-0.3%
Other developing Asia	44	48	43	44	44	-1.5%
Latin America	84	85	92	93	98	2.5%
Total	**4 684**	**4 524**	**4 510**	**4 572**	**4 727**	**0.7%**
European Union	183	178	158	155	150	-2.8%

* Estimate.

Table A.6 Met coal production, 2014-21, forecast (Mtce)

	2014	2015*	2017	2019	2021	CAGR
OECD	298	289	302	287	288	-0.1%
OECD Americas	99	80	93	73	71	-2.1%
United States	70	55	62	46	42	-4.4%
OECD Europe	22	22	16	15	14	-7.1%
OECD Asia Oceania	177	187	193	199	202	1.3%
Non-OECD	686	676	606	609	620	-1.4%
China	566	558	495	489	495	-2.0%
India	4	4	6	7	6	5.1%
Africa and Middle East	8	9	8	9	9	0.8%
Eastern Europe/Eurasia	97	92	75	80	81	-2.0%
ASEAN	1	3	6	8	10	24.7%
Other developing Asia	5	8	10	12	15	12.4%
Latin America	4	4	5	5	5	2.0%
Total	**985**	**966**	**908**	**896**	**908**	**-1.0%**
European Union	22	21	16	15	14	-6.5%

* Estimate.

Table A.7 Hard coal net imports, 2014-21, forecast (Mtce)

	2014	2015*	2017	2019	2021	CAGR
OECD	91	86	57	43	8	-32.7%
OECD Americas	- 88	- 64	- 60	- 37	- 52	-3.4%
United States	- 73	- 57	- 42	- 22	- 36	-7.4%
OECD Europe	216	219	188	167	159	-5.2%
OECD Asia Oceania	- 34	- 66	- 72	- 87	- 99	7.0%
Non-OECD	- 74	- 76	- 57	- 43	- 8	-31.3%
China	238	179	170	149	150	-2.9%
India	168	171	171	188	205	3.1%
Africa and Middle East	- 57	- 67	- 61	- 63	- 62	-1.3%
Eastern Europe/Eurasia	- 123	- 117	- 113	- 126	- 125	1.1%
ASEAN	- 295	- 240	- 218	- 187	- 168	-5.8%
Other developing Asia	50	53	50	51	52	-0.3%
Latin America	- 56	- 56	- 55	- 55	- 59	0.9%
European Union	191	185	160	138	129	-5.8%

* Estimate.

Table A.8 Seaborne steam coal imports, 2014-21, forecast (Mtce)

	2014	2015*	2017	2019	2021	CAGR
Europe	173	172	140	120	114	-6.6%
Japan	118	121	124	119	115	-0.8%
Korea	81	81	83	84	85	0.7%
Chinese Taipei	51	53	54	58	61	2.4%
China	176	121	108	106	104	-2.6%
India	130	123	126	136	142	2.4%
Latin America	20	20	21	23	24	3.3%
Other	67	76	99	128	154	12.6%
Total	**815**	**767**	**756**	**773**	**798**	**0.7%**

* Estimate.

Table A.9 Seaborne steam coal exports, 2014-21, forecast (Mtce)

	2014	2015*	2017	2019	2021	CAGR
Australia	171	179	182	189	194	1.3%
South Africa	68	69	67	70	70	0.1%
Indonesia	339	304	303	298	302	-0.1%
Russia	109	107	111	120	120	1.9%
Colombia	74	75	73	76	82	1.5%
China	5	4	7	9	11	19.9%
United States	25	18	10	8	16	-2.4%
Other	25	10	4	4	4	-15.1%
Total	**816**	**767**	**756**	**773**	**798**	**0.7%**

* Estimate.

Table A.10 Seaborne met coal imports, 2014-21, forecast (Mtce)

	2014	2015*	2017	2019	2021	CAGR
Europe	60	59	61	61	62	0.8%
Japan	49	48	52	52	51	1.0%
Korea	32	36	37	38	39	1.7%
China	56	44	41	32	31	-5.4%
India	48	47	47	58	68	6.3%
Other	21	20	25	27	29	5.9%
Total	**265**	**254**	**264**	**268**	**281**	**1.7%**

* Estimate.

Table A.11 Seaborne met coal exports, 2014-21, forecast (Mtce)

	2014	2015*	2017	2019	2021	CAGR
Australia	175	182	185	192	201	1.6%
Canada	23	21	23	24	25	3.0%
Mozambique	3	3	5	6	7	14.2%
Russia	14	11	15	16	17	7.7%
United States	44	31	30	23	24	-4.3%
Other	5	6	6	7	7	3.8%
Total	**265**	**254**	**264**	**268**	**281**	**1.7%**

* Estimate.

Table A.12 Current coal mining projects

Country	Project	Company	Type	Estimated start-up	Estimated new capacity (Mtpa)	Resource	Status
Australia	Alpha Coal Project	GVK - Hancock Coal	N	2018	32	TC	F
Australia	Appin Area 9	BHP Billiton	E	2016	3.5	CC	C
Australia	Ashton South East opencut	Yancoal Australia	E	2017	3.6	TC, PCI	F
Australia	Baralaba North expansion	Cockatoo Coal	E	2016	3.5	PCI, TC	C
Australia	Baralaba South Project	Cockatoo Coal	N	2019	3	PCI, TC	F
Australia	Belview	Stanmore Coal	N	2018	..	CC	F
Australia	Bengalla continuation	Rio Tinto / Wesfarmers	E	2018	4.3	TC	F
Australia	Bluff	Carabella Resources	N	2017	1.2	PCI	F
Australia	Broughton Coal Project	U&D Mining Industry	N	2018	1.5	CC	F
Australia	Byerwen Coal Project	Qcoal	N	2016	10	CC	F
Australia	Carmichael Coal Project (mine and rail)	Adani	N	2017	60	TC	F
Australia	Caroona	BHP Billiton	N	2020+	10	TC	F
Australia	China First Coal Project (Galilee Coal Project)	Waratah Coal	N	2018+	40	TC	F
Australia	Clyde Park Project	White Mountain	N	2020	1.75	TC	F
Australia	Codrilla	Peabody Energy	N	2020+	3.2	PCI	F
Australia	Colton	New Hope	N	2018	0.5	CC	F
Australia	Comet Ridge	Acacia Coal	N	2016	0.4	TC, CC	F
Australia	Curragh extension project	Wesfarmers	E	2018	..	CC	F
Australia	Dysart East	Dysart Coal	N	2016	1.4	CC	F
Australia	Eagle Downs (Peak Downs East underground)	Aquila Resources / Vale	N	2017	4.5	CC	C
Australia	Eaglefield	Peabody Energy	E	..	5	CC	F
Australia	Elimatta	New Hope	N	2019	5	TC	F
Australia	Fairhill	Queensland Coal Corporation	N	2017	..	CC	F
Australia	Grosvenor West	Carabella Resources	N	2020	3.8	TC, CC	F
Australia	Kevin's Corner	GVK	N	2019	30	TC	F
Australia	The Hume Coal Project	POSCO	N	..	5	TC,CC	F
Australia	Meteor Downs South	U & D Mining	N	2016	1.5	TC	F
Australia	Metropolitan	Peabody Energy	E	2015	1.5	CC	C

Australia	Minyago	Caledon Resources	N	2017	3	CC	F
Australia	Moolarben (stage 2)	Yancoal Australia	E	2016	5	TC	F
Australia	Moorlands	Cuesta Coal	N	2016	1.9	TC	F
Australia	Mount Pleasant project	Rio Tinto / Mitsubishi	N	2019	10.5	TC	F
Australia	Mt Thorley - Warkworth extension	Rio Tinto	E	..	0	TC	F
Australia	New Acland (stage 3)	New Hope Coal	E	2017	2.3	TC	F
Australia	New Lenton	New Hope Coal / MPC	N	2019	2	CC	F
Australia	North Surat - Collingwood Project	New Hope Coal	N	2018	4	TC	F
Australia	North Surat - TaroomProject	New Hope Coal	N	2018	8	TC	F
Australia	North Surat - Woori Project	New Hope Coal	N	2020	2.5	TC	F
Australia	North Galilee Project	Guildford	N	2020	7	TC	F
Australia	Oaky Creek (phase 2)	Glencore, Sumisho, Itochu, ICRA OC	E	..	5	CC	F
Australia	Project China Stone	MacMines Austasia	N	2018	55	TC	F
Australia	Red Hill Mining	BHP Billiton / Mitsubishi Alliance	N	2020+	14.5	TC,CC	F
Australia	Rolleston (phase 2)	Glencore, Sumisho, IRCA	E	..	3	TC	F
Australia	Russell Vale Colliery	Wollongong coal	E	2015	3	CC	F
Australia	Russell Vale Colliery (preliminary works project)	Wollongong coal	U	2015	nil	CC	C
Australia	Sarum	Glencore / Itochu / Sumisho	N	2017	4.2	CC	F
Australia	South Galilee Epsilon	Alpha Coal Management	N	2018	3.2	TC	F
Australia	Springsure	Springsure Mining	N	2019	1.5	PCI, TC	F
Australia	Spur Hill	Malabar Coal	N	2018	6	TC	F
Australia	Stratford	Yancoal Australia	E	2017	2.6	TC, CC	F
Australia	Styx	Waratah Coal, Queensland Nickel	N	..	1.5	PCI, TC	F
Australia	Talwood	Baosteel Resources	N	2016	3.6	PCI, TC	F
Australia	Taroborah	Shenhuo International	N	2018	5.7	TC	F
Australia	Teresa	New Emerald Coal	N	2016	6	PCI. TC	F
Australia	The Range Project	Stanmore Coal	N	n/a	5	TC	F
Australia	Togara North	Glencore	N	2017	6	TC	F
Australia	Vermont East/Wilunga	Peabody Energy	N	2015	3	PCI, TC	F
Australia	Vickery	Whitehaven	N	..	4.5	TC, CC	F
Australia	Wallarah underground	Korea Resources Corp / Sojitz Corp	N	..	5	TC	F

	longwall						
Australia	Wards Well	BHP Billiton Mitsubishi Alliance (BMA)	N	2017	5	CC	F
Australia	Washpool coal project	Aquila Resources	N	2018	2.9	CC	F
Australia	Watermark	Shenhua Energy	N	2015	6.15	TC	F
Australia	Wilton Coal project	Queensland Coal Corporation	N	2016	2	TC, CC	F
Canada	Carbon Creek	Cardero Coal	N	..	2.9	CC	F
Canada	Crown Mountain	Jameson Resources	N	2018	2	CC	F
Canada	Donkin	Glencore Xstrata, Morien Resources	N	2016	1	TC,CC	C
Canada	Echo Hill	Hillsborough Resources	N	..	1.5	TC	F
Canada	Grassy Mountain	Riversdale Resources	N	..	2	CC	F
Canada	Groundhog	Atrum Coal	N	2016	0.9	A	C
Canada	Murray River	HD Mining	N	2018	6	CC	F
Canada	Quintette	Teck Resources	N	..	3.5	CC	F
Canada	Sukunka	Glencore Xstrata	N	..	3	CC	F
Canada	Trend	Anglo American	E	2016	1	CC	C
Canada	Vista Coal Project	Coalspur mines	N	..	13	TC	F
Colombia	Canaverales	Yildirim Holding	N	2019	2.5	TC	F
Colombia	Cerrolargo Sur	Murray Energy	N	x	x	TC	F
Colombia	El Descanso	Drummond	E	x	12	TC	F
Colombia	Papayal	Yildirim Holding	N	2017	2.5	CC	F
Colombia	San Juan	Yildirim Holding	N	2019	16	TC	F
Indonesia	Bumi Barito Mineral	Cokal	N	2016	2	CC	C
Indonesia	East Kutai Coal Project	Churchill Mining / Ridlatama Group	N	..	30	TC	F
Indonesia	IndoMet Coal Project	Adaro	N	..	20	CC	F
Indonesia	Mitra Energi Agung	Indika	N	..	..	TC	F
Indonesia	Mustika Indah Permai	Adaro	N	..	..	TC	F
Indonesia	PT Bukit Enim Energi	Adaro	N	..	..	CC	F
Indonesia	PT Tekno Orbit Persada	MEC Coal	N	..	17	TC	F
Mozambique	Benga	ICVL	E	2020	8	TC	F
Mozambique	Midwest	Beacon Hill	N	..	7	TC	F
Mozambique	Moatize	Vale	E	2017	22	TC	C
Mozambique	Ncondezi	Ncondezi Energy	N	2018	7	TC	F
Mozambique	Revuboe	Nippon Steel and Sumitomo Metal	N	2016	7	CC	F
Mozambique	Zambeze	ICVL	N	..	..	CC	F
Russia	Amaam	North Pacific Coal Company	N	2017	10	CC	F
Russia	Apsatskoe	SUEK	N	2025	3	CC	C

Russia	Chulmakanskoe	Kolmar	N	2018	1.25	CC	F
Russia	Denisovsky	Kolmar	N	2016	2.5	CC	C
Russia	Elegest	TEPK	N	2020	15	CC	F
Russia	Elga	Mechel	N	2017	8	TC,CC	C
Russia	Inaglinsky	Kolmar	N	2016	6	CC	C
Russia	Karakanskoe field	Karakan Invest	N	2017	6	TC	F
Russia	Kostromovskaya	MMK, (Belon)	E	2017	1-2	CC	F
Russia	Mezhegey	Evraz	N	2016	1.3	CC	F
Russia	Solncevskoe deposit	Sakhalinugol	E	2020	10	TC	F
Russia	Urgal	SUEK	E	2016	3	TC	C
South Africa	Argent	Glencore/ Shanduka	N	2018	1.5	TC	F
South Africa	Belfast	Exxaro	N	..	2.2	TC	..
South Africa	Boikarabelo	Resgen	N	2016	6	TC	C
South Africa	Brakfontein	Goldridge	N	..	1.2	TC	C
South Africa	Consbrey	Glencore/Xstrata	N	2016	..	TC	..
South Africa	De Wittekrans	Continental	N	..	2.6	TC	..
South Africa	Elders Complex	Anglo American	N	..	..	TC	..
South Africa	Eloff	Mbuyelo	N	2016	3.3	TC	C
South Africa	Klipfontein	Eyethu	N	..	<1	TC	C
South Africa	Koornfontein OC	Glencore/Optimum	E	2019	3.3	TC	..
South Africa	Kriel	Anglo American	E/N	..	5 – 7	TC	F
South Africa	Leeupoort	Eyethu	N	2015	<1	TC	C
South Africa	Mafube life extension	Anglo American	E	..	3.5	TC	..
South Africa	Makhado	Coal of Africa	N	2016	5.5	TC, CC	F
South Africa	Matla	Exxaro	E	..	10	TC	..
South Africa	New Largo	Anglo American	N	..	12	TC	F
South Africa	Nooitgedacht	Glencore	N	2016	3	TC	F
South Africa	Smitspan	Sekoko/ Firestone energy	N	..	>1	TC	..
South Africa	Sterkfontein	Keaton Energy	N	..	1	TC	..
South Africa	Thabametsi	Exxaro	N	2016/17	3	TC	..
South Africa	Wonderfontein	Glencore/Umcebo	E	..	2.7	TC	C
South Africa	Zonnebloem	Glencore	N	2016	6	TC	F

Notes: The table lists currently discussed mining projects according to publicly available information but has no claim to completeness. Data on the start-up data is according to public information but does not necessarily represent our view concerning expected export capacity additions. Data on the estimated capacity represents the targeted capacity, which is often not available in the year of start-up.

Type: N = New project, E = Expansion

Resource: TC = thermal coal, CC = coking coal, AN = anthracite, PCI = pulverised coal injection

Status: F = Feasibility, C = Committed

Sources: McCloskey (2016), *McCloskey Coal Reports 2010-2016*, McCloskey's, London, http://cr.mccloskeycoal.com ; BREE (Bureau of Resources and Energy Economics) (2015), *Resources and Energy Major Projects*, Canberra, http://www.industry.gov.au/Office-of-the-Chief-Economist/Publications/Documents/remp/REMP-October-2015.pdf; CIAB information; various sources.

GLOSSARY

Regional and country groupings

Africa

Algeria, Angola, Benin, Botswana, Cameroon, Congo, Democratic Republic of Congo, Côte d'Ivoire, Egypt, Eritrea, Ethiopia, Gabon, Ghana, Kenya, Libya, Morocco, Mozambique, Namibia, Nigeria, Senegal, South Africa, Sudan, United Republic of Tanzania, Togo, Tunisia, Zambia, Zimbabwe and other African countries (Burkina Faso, Burundi, Cape Verde, Central African Republic, Chad, Comoros, Djibouti, Equatorial Guinea, Gambia, Guinea, Guinea-Bissau, Lesotho, Liberia, Madagascar, Malawi, Mali, Mauritania, Mauritius, Niger, Reunion, Rwanda, Sao Tome and Principe, Seychelles, Sierra Leone, Somalia, Swaziland and Uganda).

ASEAN

Brunei Darussalam, Cambodia, Indonesia, Lao People's Democratic Republic, Malaysia, Myanmar, the Philippines, Singapore, Thailand and Viet Nam.

China

Refers to the People's Republic of China, including Hong Kong.

Europe

Includes Non-OECD Europe/Eurasia, OECD Europe.

Latin America

Argentina, Bolivia, Brazil, Chile, Colombia, Costa Rica, Cuba, the Dominican Republic, Ecuador, El Salvador, Guatemala, Haiti, Honduras, Jamaica, Netherlands Antilles, Nicaragua, Panama, Paraguay, Peru, Trinidad and Tobago, Uruguay, Venezuela and other Latin American countries (Antigua and Barbuda, Aruba, Bahamas, Barbados, Belize, Bermudas, British Virgin Islands, Cayman Islands, Dominica, Falkland Islands [Malvinas], French Guyana, Grenada, Guadeloupe, Guyana, Martinique, Montserrat, St. Kitts and Nevis, Saint Lucia, Saint Pierre et Miquelon, St. Vincent and the Grenadines, Suriname and Turks and Caicos Islands).

Non-OECD Europe/Eurasia

Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Georgia, Kazakhstan, Kyrgyz Republic, Latvia, Lithuania, the Former Yugoslav Republic of Macedonia, Moldova, Romania, Russian Federation, Serbia, Tajikistan, Turkmenistan, Ukraine and Uzbekistan.

North Africa

Algeria, Egypt, Libya, Morocco and Tunisia.

OECD

Includes OECD Europe, OECD Americas and OECD Asia Oceania regional groupings.

OECD Americas

Canada, Chile, Mexico and United States.

OECD Asia Oceania

Australia, Japan, Korea and New Zealand. For statistical reasons, this region also includes Israel.[23]

OECD Europe

Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, Netherlands, Norway, Poland, Portugal, Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Turkey and the United Kingdom.

Other developing Asia

Non-OECD Asia regional grouping, excluding China and India.

List of acronyms, abbreviations and units of measure

Acronyms and abbreviations

API	Argus/McCloskey's Coal Price Index
ARA	Amsterdam Rotterdam Antwerp (price index)
ASEAN	Association of Southeast Asian Nations
BFI	blast furnace iron
BNSF	Burlington Northern Santa Fe
BOO	build-own-operate
BSPI	Bohai Rim Steam Coal Price Index
CAGR	compound annual growth rate
CCGT	combined cycle gas turbine
CCPI	China Coal Price Index
CCS	carbon capture and storage
CFR	cost freight
CHP	combined heat and power
CIF	cost, insurance and freight
CIL	Coal India Limited
CoAL	Coal of Africa Limited
CO_2	carbon dioxide
CRS	Colombian Railway System
CSDC	Chinese Slow-Down Case
CSPI	China Steam Coal Price Index

[23] The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD and/or the IEA is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

CV	calorific value
DFC	Dedicated Freight Corridor
DRI	direct reduced iron
dwt	deadweight tonnage
EIA	Energy Information Administration
EOR	enhanced oil recovery
EPA	Environmental Protection Agency
EPS	Emissions Performance Standard
ESP	electrostatic precipitator
EU	European Union
EU ETS	European Union Emissions Trading System
FID	final investment decision
FOB	free-on-board
GDP	gross domestic product
GHG	greenhouse gases
HHV	higher heating value
ICVL	International Coal Ventures Private Limited
IDA	International Development Association
IEA	International Energy Agency
IEAGHG	IEA Greenhouse Gas R&D Programme
IGCC	integrated gasification combined cycle
IMF	International Monetary Fund
IPP	independent power producers
IUP	Izin Usaha Pertambangan (Indonesian mining business license)
KAB	Kereta Api Borneo
KAI	Kereta Api Indonesia
KPK	Corruption Eradication Commission
LHV	lower heating value
LNG	liquefied natural gas
LCPD	Large Combustion Plant Directive
MATS	Mercury and Air Toxics Standards
met	metallurgical
MTCMR	*Medium-Term Coal Market Report*
MoU	memorandum of understanding
NCC	New Clydesdale Colliery
NDRC	National Development and Reform Commission (China)
NEA	National Energy Administration (China)
NO_x	nitrogen oxide
NPV	net present value
NTPC	National Thermal Power Corporation
OECD	Organisation for Economic Co-operation and Development
OSPI	Ordos Steam Coal Price Index
OTC	over the counter
PCC	post-combustion capture
PCI	pulverised coal injection
PM	particulate matter

PTBA	PT Bukit Asam
PV	photovoltaic
RBCT	Richards Bay Coal Terminal
ROW	rest of world
RZD	Russian Railways
SC	supercritical
SCPI	Shaanxi Coal Price Index
SO_2	sulphur dioxide
SO_x	sulphur oxide
SUEK	Sibirskaja ugolnaja energetitscheskaja kompanija
TCPI	China-Taiyuan Coal Transaction Price Index
TIG	Tiger Realm Coal
TPES	total primary energy supply
TRIG	transport integrated gasification
UK	United Kingdom
US	United States
USC	ultra-supercritical
VRE	variable renewable energy
WCC	Waterberg Coal Company

Currency codes

AUD	Australian dollar
CAD	Canadian dollar
CNY	Chinese yuan renminbi
COP	Colombian peso
GBP	Great Britain pound
IDR	Indonesian rupiah
PLN	Polish zloty
RUB	Russian ruble
USD	United States dollar
ZAR	South African rand

Units of measure

bcm	billion cubic metres
Bt	billion metric tonnes
°C	degrees celsius
dwt	deadweight tonnage
g/kWh	grammes per kilowatt hour
Gt	gigatonne
GW	gigawatt
kcal	kilocalories
kg	kilogramme
km	kilometre
kW	kilowatt
kWh	kilowatt hours

lbs/MWh	pounds per megawatt hour
Mbtu	million British thermal units
Mt	million tonnes
Mtce	million tonnes of coal-equivalent
$MtCO_2$	million tonnes carbon dioxide
Mtpa	million tonnes per annum
MW	megawatt
MWh	megawatt hour
t	tonne
t/GWh	tonnes per gigawatt hour
tkm	tonne kilometre
TWh	terawatt hours

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Analysis on coal often tends to be one-sided. But to truly understand the important role that coal plays, for better or worse, in the global energy system, it is critical that we examine both sides of the coin. This means understanding the implications of climate agreements on the future for coal while at the same time coming to terms with what coal is doing – and will continue to do – for energy security and energy access in developing and emerging economies.

This means taking a close look at those emerging economies, specifically in South and Southeast Asia. For example, given China's dominance in coal markets, the main problem for the coal industry is adjusting to how Chinese demand and imports will evolve in the future. In India, already the second largest coal consumer in the world, coal use is expected to grow. Will this trigger imports? Viet Nam, a net exporter until 2014, is building coal power plants at a fast pace. How much coal will they need to import? Where will that coal come from?

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